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May 8, 2006

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May 5, 2006

Via Courier

Ms. G. Cheryl Blundon
Director of Corporate Services and Board Secretary
Board of Commissioners of Public Utilities
120 Torbay Road
P.O. Box 21040
St. John's, NL A1A 5B2

Dear Ms. Blundon:

Re: Application for Approval of Recovery of Costs of 1% Sulphur Fuel through the Rate Stabilization Plan

In connection with the above application, please find enclosed four (4) copies of the following:

1. Journal Article entitled, "The Jurisdiction of Alberta's Energy and Utilities Board to Consider Broad Socio-Ecological Concerns Associated with Energy Projects" from 2005 42 Alberta Law Review, 1085-1098, by Shaun Fluker, LL.M.;

2. Decision No. 91-06-022 Re Biennial Resource Plan Update Following the California Energy Commission's Seventh Electricity Report of the California Public Utilities Commission dated June 5, 1991.

For the ease of reference of the Board panel and the other parties to the above-captioned application, these are provided and will be referred to in Argument by the Consumer Advocate. In particular, reference is directed to pages 194 and Attachment 5 at page 238 of the California Public Utilities Commission decision which illustrates how California lawmakers have, as part of that state's Public Utilities Code, directed that air quality and environmental benefits and considerations must be figured into the least cost planning concept. As regards the paper by Shaun Fluker, reference is directed to s. 3 of the Alberta Energy Resources Conservation Act (AERCA) set out at para. 6 thereof which applies where the Alberta Energy and Utility Board is exercising its jurisdiction when matters come before

AERCA.

I trust that the foregoing is found to be in order.

Yours very truly,

O'DEA, EARLE

THOMAS JOHNSON

TJ/cel
encl.

cc: Newfoundland and Labarador Hydro
Attention: Mr. Geoff Young, LL.B.

Stewart McKelvey Stirling Scales
Attention: Mr. Paul Coxworthy

Poole Althouse
Attention: Mr. Joseph Hutchings, Q.C.

Newfoundland and Labrador Power
Attention: Mr. Gerard Hayes, LL.B.

TITLE: The Jurisdiction of Alberta's Energy and Utilities Board to Consider Broad Socio-Ecological Concerns Associated with Energy Projects

AUTHOR: Shaun Fluker
SOURCE: Alberta Law Review
CITED: (2005) 42 Alta. L. Rev. 1085 - 1098

ABSTRACT: [Le résumé français suit le résumé anglais]

The Alberta Energy and Utilities Board is increasingly asked to consider the broad social, economic and environmental implications of energy exploration in Alberta. This article argues that s. 3 of the Energy Resources Conservation Act requires the AEUB to seriously consider these broad socio-ecological implications and challenges the Board's reluctance to undertake these considerations. The article also highlights the fact that this reluctance and the Board's narrow view of its s. 3 authority have yet to be assessed by the Alberta Court of Appeal.

* * *

On demande de plus en plus au Alberta Energy and Utilities Board d'envisager les vastes implications sociales, économiques et environnementales des explorations de l'énergie en Alberta. Cet article fait valoir qu'en vertu des dispositions de l'article 3 de la Energy Resources Conservation Act le AEUB devrait sérieusement en tenir compte, et questionne l'hésitation du AEUB à les considérer. L'article souligne aussi le fait que la Cour d'appel de l'Alberta n'a pas encore évalué cette hésitation ni la perspective réductionniste de l'autorité accordée au AEUB en vertu de l'article 3.

Table of Contents

The Jurisdiction of Alberta's Energy and Utilities Board to Consider Broad Socio-Ecological Concerns Associated with Energy Projects

I. Introduction

¶ 1 On 16 December 2003, the Alberta Energy and Utilities Board (AEUB or Board) issued its decision to deny a well licence for an exploratory gas well in the Whaleback region of Alberta. [See Note 1 below] The Polaris Decision was based on evidence submitted to the Board during a two-week public hearing that garnered significant media attention. The Calgary Herald published regular articles concerning the hearing and the issuance of the Polaris Decision was reported by at least one evening news telecast in Calgary. Well licence applications, submitted to the Board by the thousands every year, rarely receive such attention.

Note 1: Applications for a Well Licence, Special Gas Well Spacing, Compulsory Pooling, and Farling Permit -- Polaris Resources Ltd. (16 December 2003), AEUB Decision 2003-101, online: AEUB www.eub.gov.ab.ca/bbs/documents/decisions/2003/ 2003-101.pdf [Polaris Decision].

¶ 2 One reason for the attention here was the fact that this application concerned Alberta's Whaleback region, a unique area located along the eastern slopes (southern region) of the Rocky Mountains, southwest of Calgary. This area was the subject of a September 1994 well licence decision, wherein the Board denied an application by Amoco Canada to drill an exploratory gas well. [See Note 2 below] Subsequent to the Amoco Decision, the Alberta government designated the Whaleback region as a protected area candidate for its ecologically unique features. Ultimately, the Alberta government created two protected areas in the Whaleback: the Bob Creek Wildland Park and the Black Creek Heritage Rangeland. [See Note 3 below] These protected areas cover most, but not all, of the surface lands in the Whaleback region.

Note 2: Application for an Exploratory Well -- Amoco Canada Petroleum Company Limited, Whaleback Ridge Area (6 September 1994), ERCB Decision D94-8 [Amoco Decision].

Note 3: See O.C. 318/2003, A. Gaz. 2003.I.1710 (Provincial Parks Act, R.S.A. 2000, c. P-35) and Heritage Rangelands Designation Order, O.C. 319/2003, A. Gaz. 2003.I.1712 (Wilderness Areas, Ecological Reserves, Natural Areas and Heritage Rangelands Act, R.S.A. 2000, c. W-9), designating the Bob Creek Wildland Park and the Black Creek Heritage Rangeland.

¶ 3 The Polaris well was proposed for lands neighbouring the newly created protected areas. Some hearing participants argued that the Board ought to deny the application because the gas well would impair the ecological value of the protected areas. Other participants, including several local residents, asked the Board to deny the application because gas exploration was simply an undesirable land use activity in the Whaleback region. [See Note 4 below]

Note 4: Polaris Applications No. 1276521 and 1276489, CD ROM: Alberta Energy and Utilities Board (5 September 2003) [archived with author].

¶ 4 The AEUB denied the Polaris application based upon inadequacies in Polaris' planning, public consultations, experience and financial resources. The Board stated that it "does not feel Polaris has the ability to execute a project of this type in a manner consistent with the public interest." [See Note 5 below] Essentially, the Board denied the application on technical grounds. [See Note 6 below]

Note 5: Polaris Decision, supra note 1 at 33.

Note 6: Ibid. at 33-34.

¶ 5 The Polaris Decision is generally disappointing for what it failed to address. The Board did not offer any guidance as to whether energy exploration is a desirable land-use activity in ecologically significant areas of Alberta. Nevertheless, the Board's reliance on technical grounds to deny the application is not surprising given the Board's historical reluctance to address broad socio-ecological concerns intertwined with an individual energy project. In a 1986 well licence decision, for example, the Board expressly denied having the legal authority to address broader environmental or social concerns regarding the applied-for well licence. [See Note 7 below]

Note 7: A Report on an Application by Shell Canada Limited to Drill a Critical Sour Gas Well in the Jutland (Castle River South) Area (3 June 1986), ERCB Decision D86-2 [Jutland Decision].

¶ 6 I argue that the Board has a legal obligation to judge the desirability of an individual energy project, such as the proposed Polaris well, on broad socio-ecological concerns. The AEUB's obligation in this regard comes, in part, from s. 3 of the Energy Resources Conservation Act:

> Where by any other enactment the Board is charged with the conduct of a hearing, inquiry or other investigation in respect of a proposed energy resource project, it shall, in addition to any other matters it may or must consider in conducting the hearing, inquiry or investigation, give consideration to whether the project is in the public interest, having regard to the social and economic effects of the project and the effects of the project on the environment. [See Note 8 below]

Note 8: R.S.A. 2000, c. E-10, s. 3 [ERCA]. Section 3 was initially enacted as s. 2.1 in 1993.

In contrast to the argument presented here, the Board has narrowly interpreted its obligations under ERCA s. 3, suggesting that this provision falls short of providing the Board with authority to address broad socio-ecological concerns associated with energy projects. My purpose in this article is to note some deficiencies with the Board's narrow interpretation and highlight that the Board's view has yet to be assessed by the Alberta Court of Appeal. [See Note 9 below]

Note 9: My LL.M. thesis examines the Board's authority in ERCA s. 3 to address broad socio-ecological concerns associated with energy projects. The thesis critiques the Board's interpretation of this authority in well licence decisions along the eastern slopes of the Canadian Rocky Mountains, and the thesis uses the concept of ecological integrity to suggest how this authority should be interpreted and applied by the Board. The thesis includes an examination of Alberta Court of Appeal jurisprudence to assess whether the Board's narrow interpretation of ERCA s. 3 is a substantive jurisdictional error. See Shaun Fluker, The Alberta Energy and Utilities Board: Ecological Integrity and the Law (LL.M. Thesis, University of Calgary, 2003) [unpublished]. The limited scope of this article draws from the thesis, and interested readers should consult the thesis for additional analysis.

II. A Brief History of the AEUB

¶ 7 The AEUB was formed in 1995 on the amalgamation of Alberta's Public Utilities Board and Energy Resources Conservation Board (ERCB). [See Note 10 below] The ERCB began as the 1932

Turner Valley Gas Conservation Board with a mandate to reduce the level of natural gas flaring in the Turner Valley oil field. [See Note 11 below] The Turner Valley Board was disbanded after legal challenges, immense opposition from industry and political unrest during the 1930s. [See Note 12 below] Alberta's interest in implementing resource conservation did not subside, however, and in 1938 the Alberta government created the Petroleum and Natural Gas Conservation Board with expanded powers to regulate the ever increasing production of oil and natural gas from the Turner Valley field. [See Note 13 below] By 1950, the oil and gas industry had begun its rise to prominence as Alberta's dominant economic sector and the Petroleum and Natural Gas Conservation Board was a key decision-maker, promoting oil and gas exploration and recovery while implementing resource conservation. In 1971, the Board became known as the ERCB, with expanded authority to regulate the exploration and development of any source of energy in Alberta. The ERCB and its predecessors had evolved from a bold attempt to implement resource conservation on a reluctant, relatively isolated industry in Turner Valley to a widely respected regulator of all energy resources and a key player in a dominant economic sector. [See Note 14 below]

Note 10: I am not concerned with the Public Utilities Board so my historical discussion focuses solely on the background of the Energy Resources Conservation Board. Throughout this article I refer to the ERCB and the AEUB interchangeably as the context dictates.

Note 11: David H. Breen, Alberta's Petroleum Industry and the Conservation Board (Edmonton: The University of Alberta Press, 1993). Breen notes this was Alberta's first formal regulatory attempt to implement resource conservation in the infant oil and gas industry (ibid. at 79-94).

Note 12: Ibid.

Note 13: Resource conservation is commonly defined as ensuring maximum ultimate resource recovery with minimal waste (ibid. at xxvii-xxxi).

Note 14: The Board is currently responsible for administering a wide range of energy and utilities legislation in Alberta. See e.g. online: Alberta Energy and Utilities Board www.eub.gov.ab.ca.

¶ 8 The Board was, and remains, a creature of statute; currently the Alberta Energy and Utilities Board Act. [See Note 15 below] AEUB decision-making authority is governed in part by the purpose provisions in the umbrella ERCA and several resource-specific statutes such as the Oil and Gas Conservation Act. [See Note 16 below]

Note 15: R.S.A. 2000, c. A-17, s. 2 [AEUB Act].

Note 16: R.S.A. 2000, c. O-6 [OGCA]. Additional resource-specific statutes include the Coal Conservation Act, R.S.A. 2000, c. C-17 and the Oil Sands Conservation Act, R.S.A. 2000, c. O-7.

III. The Need to Address Broad Socio-Ecological Concerns

¶ 9 The AEUB is increasingly asked to consider the broad social, economic and environmental implications of energy exploration in Alberta. [See Note 17 below] While strong arguments have been made against addressing broader concerns in an individual energy project review, there will be times where an individual energy project review can fill gaps in broader land use policies and/or initiate evolution at this broader level to accommodate changing socio-ecological values in a region. [See Note 18 below]

Note 17: For example in Strathcona County, a densely populated region east of Edmonton, elected officials sought to meet with AEUB staff to address the County's concerns over a proposed application to drill several gas wells in the County. Their concerns included the absence of a policy that addresses issues particular to drilling wells in areas of high human populations (Humberto Bonizzoni, "Strathcona to meet with EUB officials" This Week [Sherwood Park] (14 February 2003) 13).

Note 18: Steven Kennett and Monique Ross, In Search of Public Land Law in Alberta (Calgary: Canadian Institute of Resources Law, 1998) at 32-37; my LL.M. thesis argues this point in more detail. See Fluker, supra note 9. See also Michael Wenig, "Cumulative Effects: Oil, Gas, and Biodiversity" (2002) 27:2 Law Now 27. Wenig argues that the AEUB is capable of influencing the broader land use policy to seriously consider cumulative effects of oil and gas development in Alberta.

¶ 10 For example, the Board's 1994 Amoco Decision effectively reversed existing provincial land use policy in the Whaleback region. Prior to this decision, the provincial government had issued subsurface mineral rights to Amoco Canada for energy exploration in the Whaleback. The Board denied Amoco's well licence application, citing the need to preserve nature in the region. [See Note 19 below] Ultimately the provincial government created two protected areas in the Whaleback, effectively removing these areas from future subsurface mineral rights disposition. Had the Board approved Amoco's exploratory well in 1994, the Whaleback might be a producing gas field today. Instead, the Board's decision initiated an evolution in provincial land use policy to accommodate socio-ecological values that had been articulated during the well licence hearing. Accordingly, even if it lacks the ultimate authority to implement solutions to broad socio-ecological problems, the AEUB can address these problems by initiating a process towards those solutions. [See Note 20 below]

Note 19: Amoco Decision, supra note 2 at 33-34. In its discussion of land use issues, the Board expressed its concerns for preserving ecological integrity in the Whaleback, describing the region as relatively undisturbed by humans.

Note 20: Interestingly, the Board has expressly disagreed with the suggestion that its project decisions can be the initiator for change in broader land use decision-making. See Applications for well licences -- Moose Mountain Area Husky Oil Operations Ltd. (11 March 1994), ERCB Decision D 94-2 [Moose Mountain Decision].

¶ 11 Implicitly or explicitly, however, the AEUB assumes that the desirability of an individual energy project can be assessed apart from these broader concerns. This assumption allows the Board to avoid an inclusive, integrated consideration of the socio-ecological effects intertwined with energy projects.

¶ 12 The Board's reluctance to address these broader concerns is also consistent with the resource ethic that guides it. The Board promotes resource conservation; the maximum recovery of energy resources with minimal waste. The Board regulates the supply of resources from an ecological system to a social system. This approach is consistent with the dominant western worldview that nature is simply a collection of resources available for humans to use in their quest for happiness. [See Note 21 below]

Note 21: Aldo Leopold critiques the morality of the resource ethic in his seminal essay the "Land Ethic." See Aldo Leopold, A Sand County Almanac and sketches here and there (New York: Oxford University Press, 1949) at 202. See also Carolyn Merchant, "Reinventing Eden: Western Culture as a Recovery Narrative" in William Cronon, ed., Uncommon Ground: Rethinking the Human Place in Nature (New York: W.W. Norton and Company, 1996) 132. Merchant conceptualizes the dominant western worldview as a male recovery narrative that begins with the fall from the Garden of Eden. Humans (males) are striving to recover from the fall using science and capitalism as tools to subdue the Earth and transform it into the Garden.

¶ 13 In the 1994 Amoco Decision, the Board denied project approval in order to protect nature. This decision reflected the introduction of a preservationist philosophy into western thought and, subsequently, the Board's decision-making process. [See Note 22 below] The need to preserve areas of nature apart from human influence is based on the view that humans are destined to destroy nature. [See Note 23 below] The preservation ethic is arguably the resource ethic in new clothing. Nature remains a collection of resources. According to this version, however, an ecological system is a more valuable resource than humans themselves and thus ought to be preserved from the influence of social systems. [See Note 24 below]

Note 22: A recent example of a preservationist philosophy that argues nature ought to be preserved from human influence is Laura Westra, An Environmental Proposal for Ethics: The Principle of Integrity (Lanham, Md.: Rowman and Littlefield Publishers, 1994).

Note 23: Ibid.

Note 24: Bruce Morito, "Examining Ecosystem Integrity as a Primary Mode of Recognizing the Autonomy of Nature" (1999) 21 Environmental Ethics 59.

¶ 14 These dichotomous approaches, whereby the needs of humans and nature are understood as mutually exclusive and the human-nature relationship is a hierarchical one, avoids difficult questions concerning the desirability of energy projects in Alberta. [See Note 25 below] Should energy projects be located in or near densely populated areas of the province? Should regional health concerns, human or otherwise, prevent the Board from approving an individual project decision? When they are put to the Board, these questions require the AEUB to consider integrated socio-ecological concerns rather than a partial consideration that implicitly selects economic development (resource ethic) over environmental preservation (preservation ethic) or vice versa on a case-by-case basis.

Note 25: The problems presented by the human/nature dichotomy are thoroughly explored in Uncommon Ground: Rethinking the Human Place in Nature, supra note 21. Legal scholars have also devoted some attention to the troublesome aspects of this dichotomy. See Eric. T. Freyfogle, "The Ethical Strands of Environmental Law" (1994) U. Ill. L. Rev. 819 at 833: "The dominant moral view today is largely dualistic -- humans are subjects, nature is an object -- and the implications of this duality are as plain as they are destructive." See also Carol M. Rose, "Given-ness and Gift: Property and the Quest for Environmental Ethics" (1994) 24 Environmental Law 1. Rose observes that dominant western ethics view nature either as ethically neutral and "up-for-grabs" or as a gift to be preserved from use altogether. Rose argues that we need normative guidance in the middle of these two extremes, a norm of "use with restraint" (ibid. at 7-14).

¶ 15 Human social systems rely upon the energy and components of their surrounding ecological systems for sustenance. In the process of sustaining themselves, social systems alter the structure and processes of ecological systems by, for example, developing new energy projects. An altered ecological system, in turn, influences a social system in desirable or undesirable ways. Section 3 of the ERCA explicitly requires the Board to consider the integrated social, economic and environmental effects of an individual energy project as part of its decision-making process. The section is an acknowledgement that the Board's decision to issue or deny regulatory approval is, in essence, a choice between broader views concerning desirable socio-ecological states and an opportunity to select the desirable from the undesirable socio-ecological relationships in a region.

¶ 16 Prior to 1993 most commentators and the courts agreed that the Board's jurisdiction to address the broad socio-ecological effects of energy projects was limited. While commentators generally agree that the 1993 enactment of ERCA s. 2.1 (now s. 3) enhanced the Board's jurisdiction to consider socio-ecological concerns, the Board has stated that the 1993 enactment simply confirmed the status quo. The two Alberta Court of Appeal decisions that have considered the Board's ERCA s. 3 obligations contribute little to this debate.

IV. Prior to 1993: The Resource Ethic

¶ 17 In the late 1970s the ERCB approved an oilsands project in northern Alberta. During the project review process, local First Nations communities requested the ERCB to condition its approval on the implementation of an affirmative action program. The federal government endorsed the request and a subsequent ERCB project report to the Alberta government was also sympathetic to the program. Nevertheless, at the hearing the ERCB held that it did not have jurisdiction to attach the condition to its project approval.

¶ 18 Ultimately the Supreme Court of Canada held that the ERCB was correct. Referring to the purpose provisions of the then governing Alberta legislation, the Court unanimously found the ERCB's jurisdiction was

> limited to the regulation and control of the development of energy resources and energy in the Province of Alberta. The powers with which the Board is endowed are concerned with the natural resources of the area rather than with the social welfare of its inhabitants, and it would, in my view, require express language to extend the statutory authority so vested in the Board so as to include a program designed to lessen the age-old disadvantages which have plagued the native people since their first contact with civilization as it is known to the great majority of Albertans. [See Note 26 below]

Note 26: Athabasca Tribal Council v. Amoco Canada Petroleum Co., [1981] 1 S.C.R. 699 at 708, aff'g (1980), 22 A.R. 541 (C.A.) [Athabasca Tribal Council]. The ERCB governing legislation at this time was identical, in all material respects, to the current content of ERCA, supra note 8, s. 2 and OGCA, supra note 16, s. 4, but did not include the subsequently enacted ERCA, ibid., s. 2.1.

¶ 19 In subsequent years, several commentators have relied on Athabasca Tribal Council as limiting the Board's jurisdiction to consider the social or environmental impacts from energy projects. [See Note 27 below] P.S. Elder noted that the Supreme Court of Canada took a narrower view than did the Alberta

Court of Appeal in its interpretation of the ERCB's jurisdiction. [See Note 28 below] The Court of Appeal distinguished between project-related social impacts and pre-existing social problems, holding that the ERCB had jurisdiction to address the former:

Note 27: See e.g. Michael J. Bruni and Keith F. Miller, "Practice and Procedure before the Energy Resources Conservation Board" (1982) 20 Alta. L. Rev. 79 at 83-84; Peter McLaws and Susan Blackman, "The Environmental Mandate of the ERCB in Well Licence Applications" (1989) 28 Resources 1 at 2-3; Francis M. Saville and Richard A. Neufeld, "The Energy Resources Conservation Board of Alberta and Environmental Protection" (1989) 2 Can. J. Admin. L. and Prac. 287 at n. 8; Francis M. Saville and Richard A. Neufeld, "Project Approvals under Proposed Alberta Environmental Legislation" (1991) 4 Can. J. Admin. L. and Prac. 275 at 289-90.

Note 28: P.S. Elder, "Environmental Impact Assessment in Alberta" (1985) 23 Alta. L. Rev. 286 at 303-305.

> In considering the extent of the Board's jurisdiction over social problems, I distinguish between those problems which might be expected to be created by the project and those which exist without it. The ERCB has attempted in its report and recommendations to anticipate those problems which would be created by the project and to propose remedies and solutions for them. In doing so, it was in my opinion acting within the jurisdiction given it by the Energy Resources Conservation Act and the Oil and Gas Conservation Act. It would, however, in my opinion require clear and express language to confer on the Board a jurisdiction to solve the pre-existing social problems of Alberta in the course of approving or disapproving such a project. [See Note 29 below]

Note 29: Athabasca Tribal Council v. Amoco Canada Petroleum Company Ltd. (1980), 22 A.R. 541 at para. 20 (C.A.), aff'd [1981] 1 S.C.R. 699. The Court of Appeal was divided. Morrow J.A., in dissent, held that the appellant's concerns could be addressed by the ERCB:

> [J]ust as the Board must work from the environment as it finds it now, so must it take as part of this environment, as it were, the social conditions. Environment surely does not just mean trees, birds and animals. I should hope that in the semi-virginal area in which the proposed development under consideration here the nature of the existing settlements, social structure of the residents, and their state of economic and social development is both apparent and has to be of concern to anybody, as in this case, the Board, called upon to recommend in 'the public interest' (ibid. at para. 43).

Elder argued that the Supreme Court of Canada, while endorsing the Court of Appeal result, rejected any distinction between project-related and pre-existing social issues: "The narrower view would imply that the ERCB enjoys little, if any, mandate to make approval conditions regarding social impacts and a fortiori cannot require or hear evidence for these purposes." [See Note 30 below] Athabasca Tribal Council has also been relied on for the proposition that "the Board cannot deny a well licence application purely for environmental reasons.... This is a policy issue best left to elected representatives." [See Note 31 below]

Note 30: Elder, supra note 28 at 304.

Note 31: McLaws and Blackman, supra note 27 at 3. Saville and Neufeld offered a contrasting view: "[I]t is clear from the purpose provisions of the ERCA that protection of the environment in the course of energy development is one of the objectives which the legislature has determined ought to be pursued by the Board" (Saville and Neufeld, "The Energy

Resources Conservation Board of Alberta and Environmental Protection," supra note 27 at 289).

¶ 20 The Supreme Court of Canada, along with most commentators prior to 1993, endorsed the ERCB's resource ethic and its view of nature as simply a collection of resources available for humans to use in their quest for happiness.

V. The 1993 Enactment of ERCA Section 2.1 (Now Section 3)

¶ 21 In the early 1990s, the Province of Alberta began a review of its environmental legislation. [See Note 32 below] One aspect of this renewal process was the 1991 release of an environmental legislative review report. [See Note 33 below] The mandate of the Environmental Legislation Review Panel was to obtain, consider and report to the provincial Minister of the Environment on public opinion concerning proposed omnibus environmental legislation. [See Note 34 below] Many public comments suggested that the ERCB mandate ought to include jurisdiction to reject project proposals on environmental grounds. [See Note 35 below] The Panel, however, felt "that the ERCB inevitably must give priority to energy development, given its legislated mandates." [See Note 36 below] Asking a board charged with energy resource development to reject an energy project on environmental grounds was seen as asking too much. [See Note 37 below] Nevertheless, the Panel recommended the ERCB's governing legislation include a provision analogous to that governing Alberta's Natural Resources Conservation Board (NRCB), [See Note 38 below] a provision requiring the Board to consider the economic, social and environmental effects of an energy project. [See Note 39 below] Consequently, s. 2.1 of the ERCA was enacted in 1993. [See Note 40 below]

Note 32: The impetus for change included the legal entrenchment of environmental assessment at the federal level. Canadian Wildlife Federation Inc. v. Canada (Minister of the Environment), [1989] 26 F.T.R. 245 (T.D.), aff'd [1990] 2 W.W.R. 69 (F.C.A.), is the seminal judicial ruling that, to the surprise of the federal government, declared federal environmental assessment guidelines to be mandatory and legally enforceable. Subsequently in Friends of the Oldman River Society v. Canada (Minister of Transport), [1992] 1 S.C.R. 3, the Supreme Court of Canada held these guidelines to be intra vires Parliament.

Note 33: Alberta, Report of the Environmental Legislation Review Panel (Edmonton: Government of Alberta, 1991).

Note 34: The proposed legislation is now enacted as the Environmental Protection and Enhancement Act, R.S.A. 2000, c. E-12.

Note 35: Report of the Environmental Legislation Review Panel, supra note 33 at 31.

Note 36: Ibid. at 36.

Note 37: Brian O'Ferrall, "The E.R.C.B. and the N.R.C.B.: Are they equivalent?" (1992) 7:2 Environmental Law Centre News Brief 1.

Note 38: The NRCB provides an overview of itself on its internet site, online: NRCB www.nrcb.gov.ab.ca. The NRCB reviews non-energy resource projects in Alberta, such as forest, recreation, mining and water management projects. NRCB board members are appointed by provincial cabinet, and its decisions must be approved by provincial cabinet.

Note 39: Report of the Environmental Legislation Review Panel, supra note 33 at 36. Alternatively, the panel recommended that energy projects, otherwise subject to ERCB approval and requiring an environmental assessment, be required to obtain NRCB approval (ibid.). Wendy Francis, a panel member, noted that "[t]he Panel recommended that the Board's legislation be amended to give it powers analogous to those wielded by the Natural Resources Conservation

Board" (Wendy Francis, Sustainable Development and Environmental Assessment in Alberta: Not Heaven in a Single Bound (LL.M. Thesis, University of Calgary, 1994) at 115 [footnote omitted] [unpublished]).

Note 40: Environmental Protection and Enhancement Act, S.A. 1992, c. E-13.3, s. 246(5). Section 246(5) states:

> The Energy Resources Conservation Act is amended ... by adding the following after section 2:
>
> > 2.1 Where by any other enactment the Board is charged with the conduct of a hearing, inquiry or other investigation in respect of a proposed energy resource project, it shall, in addition to any other matters it may or must consider in conducting the hearing, inquiry or investigation, give consideration to whether the project is in the public interest, having regard to the social and economic effects of the project and the effects of the project on the environment [emphasis in original].

¶ 22 Some members of the Environmental Legislation Review Panel argued that ERCA s. 2.1 enhanced the ERCB's environmental jurisdiction. [See Note 41 below] Commentators have subsequently argued that ERCA s. 2.1 has broadened the ERCB's jurisdiction to consider cumulative socio-ecological effects and implement sustainable development. [See Note 42 below]

Note 41: O'Ferrall, supra note 37 at 3; Francis, supra note 39 at 115.

Note 42: See e.g. Steven Kennett, "The ERCB's Whaleback Decision: All Clear on the Eastern Slopes?" (1994) 48 Resources 1; Steven Kennett, "The Castle -- A Litmus Test for Alberta's 'Commitment' to Sustainable Resource and Environmental Management" (2003) 83/84 Resources 1 at 4; George L. Hegmann and G.A. Yarranton, Cumulative Effects and the Energy Resources Conservation Board's Review Process (Calgary: Macleod Institute for Environmental Analysis, 1995) at 4; Neil J. Brennan, "Private Rights and Public Concerns: The 'Public Interest' in Alberta's Environmental Management Regime" (1997) 7 J. Envtl. L. and Prac. 243 at 251; Wenig, supra note 18 at 29.

¶ 23 However, not everyone agrees with these views. In 1992 Phil Prince, then Vice-Chairman of the ERCB, argued that the introduction of ERCA s. 2.1 was intended to communicate more effectively the already existing ERCB role in protecting the environment. [See Note 43 below] Prince suggested that the potential for conflict between development and the environment was a primary justification for the existence of the ERCB. [See Note 44 below] Section 2.1 of the ERCA simply confirmed that the ERCB must adjudicate the conflict by weighing the benefits of energy development against its social and environmental costs: "When, after all possible mitigation, the costs of using the environment still exceed the benefits, the activity should be precluded." [See Note 45 below] According to Prince, ERCA s. 2.1 simply confirmed the status quo concerning the Board's mandate: the obligation to govern the appropriateness of an energy project with a cost/benefit analysis.

Note 43: Phil Prince, "The E.R.C.B. and the N.R.C.B.: A response to Mr. O'Ferrall" (1992) 7:3 Environmental Law Centre News Brief 3.

Note 44: Ibid. at 4.

Note 45: Ibid. at 5. Prince noted that some "costs" are difficult to quantify, therefore subjective assessments are sometimes required (ibid. at n. 4).

VI. The AEUB Interpretation of ERCA Section 3

¶ 24 In a March 1994 well licence decision, the Board itself observed that ERCA s. 2.1 (now s. 3) did not fundamentally alter its mandate. [See Note 46 below] In its September 1994 Amoco Decision, the Board confirmed that addressing the socio-ecological effects of a gas well requires the Board to ask whether the potential "benefits" to be derived from a successful well exceed the "costs" measured in social or ecological terms:

Note 46: Moose Mountain Decision supra note 20 at 12 .

> Ultimately, each applicant is responsible for identifying issues and addressing those issues to the degree to which it believes appropriate. The Board is then charged with measuring the application against the broad test of "public interest", including environmental, social, and economic costs and benefits.
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> ...
>
> While the Board accepts Amoco's right to explore for and develop hydrocarbons in the Whaleback and therefore its need for the well, the Board does not believe that either the acquisition of mineral rights or a surface lease agreement in any way automatically confers the right of an applicant to a well licence. The Board must balance Amoco's need for the well against the potential economic, social, and environmental costs and benefits accruing to the public from the exploration well.... The Board must be convinced that certain safety, social, and environmental impacts can be or will be satisfactorily mitigated before the well would be approved.
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> ...
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> In the Board's view, the most significant issue is whether the benefit of the information which would be supplied by the exploratory well outweighs the environmental, social, and economic costs associated with such a development within the Whaleback. [See Note 47 below]

Note 47: Amoco Decision, supra note 2 at 10, 12-13, 34. The Board had relied on the cost/benefit approach prior to 1993. For example, see the Jutland Decision, supra note 7, and the Shell Canada Limited Application for a Well Licence, Waterton Field (22 December 1988), ERCB Decision D88-16 [Whitney Creek Decision]. For additional statements from the Board confirming its cost/benefit application of ERCA s. 3 see Application to construct and operate two sour oil effluent pipelines and associated facilities -- Husky Oil Operations Ltd., Moose Field (9 April 1998), ERCB Decision 97-17 (Addendum) at 6-8 and Application for a well licence -- Shell Canada Limited, Ferrier Field (20 March 2001), AEUB Decision 2001-09 at 29, 34, online: AEUB www.eub.gov.ab.ca/bbs/documents/decisions/ 2001/2001-09.pdf [Ferrier Decision]. For a recent cost/benefit interpretation by the Board see the Polaris Decision, supra note 1 at 3, 5, 33.

¶ 25 The AEUB views s. 3 of the ERCA as confirmation that it must ask whether the economic benefits of an energy project exceed its immediate social and environmental costs. Where the economic benefits of the project exceed its immediate social or environmental costs, the AEUB approves the project. Where the costs exceed the benefits, project approval is denied unless the costs can be sufficiently mitigated with conditions or otherwise.

¶ 26 Utilitarian cost/benefit analysis is popular with public decision-makers, in part, because it purports to produce unambiguous decisions by weighing the good consequences of an action against the bad. [See Note 48 below] However, benefits and costs are typically valued monetarily and non-measurable or qualitative consequences are discounted or excluded altogether in these calculations. [See Note 49 below] In addition, as Mark Sagoff explains:

Note 48: Bruce Morito, Thinking Ecologically: Environmental Thought, Values and Policy (Black Point, N.S.: Fernwood Publishing, 2002) at 105-106.

Note 49: Ibid. at 45-51. Morito notes that the preference for quantitative data developed at a time when mechanistic cause-and-effect was replacing metaphysical explanations in the pursuit of knowledge.

> This approach denies the educative function of political discussion.... The reasons people give for their views ... are not to be counted; what counts is how much individuals will pay to satisfy their wants. Those willing to pay the most, for all intents and purposes, have the right view; theirs is the better judgment, the deeper insight, and the more informed opinion. [See Note 50 below]

Note 50: Mark Sagoff, The Economy of the Earth: Philosophy, Law, and the Environment (Cambridge: Cambridge University Press, 1988) at 41-42.

Critics of cost/benefit analysis agree that it is a useful decision-making tool, particularly when efficiency is the goal. They disagree, however, that its conclusions ought to be the decisive factor in decision-making. [See Note 51 below]

Note 51: There is a vast literature concerning the debate over the merits of cost/benefit analysis as a decision-making tool. I only scrape the surface of this debate. For an introduction to the area see Donald VanDe Veer and Christine Pierce, eds., The Environmental Ethics and Policy Book: Philosophy, Ecology, Economics, 3d ed. (Belmont, CA: Wadsworth, 2003) at 336-50. This introductory source provides a concise summary of arguments for and against the use of cost/benefit analysis as a decision-making tool.

¶ 27 The Board relies exclusively on a cost/benefit analysis to assess the desirability of an energy project's socio-ecological impact. As such, the Board relies on unsubstantiated and unstated assumptions in making its energy project decisions. [See Note 52 below] For example, the Board assumes that measurable quantities form the only basis of knowledge. [See Note 53 below] This assumption enables the Board to exclude or discount non-measurable socio-ecological information without justification; information that typically reveals broader views on the desirability of an energy project's socio-ecological impacts but which, at the same time, would cloud the Board's seemingly unambiguous cost/benefit analysis.

Note 52: My LL.M. thesis argues this point in more detail. See Fluker, supra note 9.

Note 53: See Bonterra Energy Corp. Application for a Well Licence, Pembina Area (24 January 2003), AEUB Decision 2003-008, online: AEUB www.eub.gov.ab.ca/bbs/documents/ decisions/2003/2003-008.pdf. In this decision, the Board discounted observational evidence on wind direction because it was not based on any science or technical measurements. In the Jutland Decision, the Board discounted qualitative evidence provided by local commercial operators opposing the gas wells (Jutland Decision, supra note 7 at 22). The Board similarly discounted non-quantitative evidence in Whitney Creek Decision, supra note 47 at 21-22. The Board has consistently lamented the absence of quantitative data to measure socio-ecological impacts from energy projects. For another example see Ferrier Decision, supra note 47 at 27-29.

VII. Judicial Consideration of ERCA Section 3

¶ 28 The Alberta Court of Appeal has considered ERCA s. 3 (2.1 as it was then) on two occasions and referred to the section in several leave to appeal applications. [See Note 54 below] In its two decisions, however, the Court failed to provide any insight towards how ERCA s. 3 should be interpreted.

Note 54: The Court has referred to ERCA s. 3 in several leave applications: Calgary North H2S Action Committee v. Alberta (Energy and Utilities Board), 1999 ABCA 323; ConCerv v. Alberta (Energy and Utilities Board), 2001 ABCA 217; Pembina Institute for Appropriate Development v. Alberta (Energy and Utilities Board), 2002 ABCA 184. Section 41 of the ERCA states that leave to appeal a Board decision must be obtained from the court before the appeal will be heard. For a recent statement from the court concerning the test for granting leave, see Prince Resource Corp. v. Alberta (Energy and Utilities Board), 2003 ABCA 243.

¶ 29 In Rocky Mountain Ecosystem Coalition v. Alberta (Energy and Utilities Board) [See Note 55 below] leave to appeal was granted on two grounds, namely: (a) did ERCA s. 2.1 have any impact on the general policies and procedures of the Board in fulfilling its functions in relation to applications for gas removal permits; and (b) regardless of (a), has the Board, in deciding the matter at hand, complied with its ERCA s. 2.1 mandate? The Court held that ERCA s. 2.1 did not alter the discretion of the AEUB to issue or deny gas export permits, but the Court expressly declined to affirm the AEUB's general interpretation of ERCA s. 2.1:

Note 55: (1996), 178 A.R. 106 (C.A.) [RMEC].

> Although the Board does not expressly state that the amending s. 2.1 imposes no further obligation on the Board to consider the social, economic and environmental effect, it is clear that it views the amendments as confirming what the Board has in fact been considering at the various stages requiring its approval.
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> ...
>
> We affirm the Board's decision that the export permit stage is an inappropriate point to

> consider anew the social, economic and environmental impact beyond the Board's existing policies and procedures. It is thus not necessary and we do not decide that the amendments require the Board to expand or alter its existing policies and approval procedures to comply with the amendments. We do note, however, the explicit mandate in 2.1 that the Board: "shall, in addition to any other matters it may or must consider ... [determine] whether the project is in the public interest, having regard to the social and economic effects of the project." It would appear to be arguable that the Board can continue with its existing policies and procedures regarding the earlier stages of its approval process without some express heed to the mandatory words of the amendments. However, that issue is not before us. Apart from our observation, we do not decide that matter. [See Note 56 below]

Note 56: Ibid. at paras. 7, 10 [emphasis in original]. The emphasis in the text suggests that the Court intended to say the Board "cannot" continue with its existing policies. Otherwise, the Court appears to contradict itself in this paragraph of the judgment.

The Court's refusal to address the Board's general ERCA s. 2.1 mandate is astonishing in light of the fact that leave had been granted precisely on this question. [See Note 57 below]

Note 57: Nigel Bankes, "Environmental Security and Gas Exports" (1996) 53 Resources 1 at 3.

¶ 30 The second case, Coalition of Citizens Impacted by the Caroline Shell Plant v. Alberta (Energy and Utilities Board), [See Note 58 below] involved the review of an AEUB approval allowing an increase in the processing capability of a gas facility. [See Note 59 below] In its decision, the AEUB acknowledged that the increased processing would result in an increase of sulphur dioxide emissions. [See Note 60 below] It also acknowledged community concerns regarding the potential health effects on animals resulting from general oil and gas operations in the area. [See Note 61 below] Nevertheless, the AEUB refused to hear evidence during the hearing regarding the impact of these increased emissions on local cattle. The AEUB indicated that it would rely on the findings of a broader, concurrent Alberta Cattle Commission study, not yet finalized at the time of the hearing. The Coalition challenged this refusal to hear site-specific evidence and deferral to the broader study.

Note 58: (1996), 187 A.R. 205 (C.A.) [Caroline Shell Plant].

Note 59: Shell Canada Limited -- Application for increased throughput sour gas plant -- Caroline Field (9 April 1997), AEUB Decision 97-5.

Note 60: Ibid. at 6.

Note 61: Pre-hearing meeting Shell Canada Limited (27 June 1996), AEUB Decision 97-5.

¶ 31 The appellants contended that the AEUB, by refusing to hear the site-specific evidence, failed to meet its ERCA s. 2.1 obligations. The Court disagreed, stating that "the decision of the Board to limit the evidence it will hear does not indicate that it has or will fail to comply with the requirements of s. 2.1." [See Note 62 below] The Court offered little substantive analysis of what ERCA s. 2.1 allows or requires the AEUB to consider, limiting its discussion to three points. First, the Court noted that social, environmental and economic effects were considered by the Board as part of its facility construction review several years earlier. Second, the Court noted that the current proposal would be subject to examination by the "environmental authorities." [See Note 63 below] Finally, the Court held that the AEUB did not err by delaying a consideration of the emissions issue until after the completion of the broader study.

Note 62: Caroline Shell Plant, supra note 58 at para. 17.

Note 63: Ibid. at para. 20. This observation implies that the Court did not view the AEUB as an environmental authority, consistent with the 1981 Supreme Court of Canada Athabasca Tribal Council decision, supra note 26.

¶ 32 However, the Court was not unanimous. Justice Conrad, in dissent, noted that ERCA s. 2.1 required the AEUB to consider the social and environmental effects of projects in its deliberations. This legislative direction, together with the AEUB's acknowledgement of community concerns, led her to conclude that the emissions evidence was relevant in this case. Unlike the majority decision, Conrad J.A. provided some substantive analysis of ERCA s. 2.1:

> Section 2.1 requires that the Board inquire into whether the project is in the public interest, having regard to the social and economic effects of the project and the effects of the project on the environment. The effects of the incremental increase on cattle would be relevant to that statutory obligation, just as it is necessary to consider the effects of the incremental increase on human health.
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> ...
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> Ranchers have filed complaints saying that the existing level of emissions are showing visible signs of affecting cattle. What could be more relevant? To hold that actual observations of cattle at various times, in various weather conditions, at various rates of emissions are not relevant would be patently unreasonable and an error.
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> ...
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> The Board has declined jurisdiction by refusing to recognize the statutory duty imposed on it by s. 2.1 of the E.R.C. Act to hear evidence of the impact on cattle before making its decision. It cannot delegate its duty to deal with that problem to another body, or at a later date. [See Note 64 below]

Note 64: Caroline Shell Plant, supra note 58 at paras. 43, 47-48.

The failure by the majority judgment in Caroline Shell Plant to offer any insight into how s. 3 of the ERCA should be applied is disappointing. In its two decisions, the Court of Appeal has either avoided the issue altogether or it has simply referred to the section without analysis. Over a decade has passed since the enactment of ERCA s. 3. We still await substantive judicial assessment on the appropriateness of the AEUB's limited treatment of the complexities of intertwined economic, social and environmental values in energy development, and the appropriateness of the Board's view that the 1993 enactment of ERCA s. 3 simply confirmed the status quo.

VIII. Conclusion

¶ 33 The AEUB, the primary energy project decision-maker in the province, should play a crucial role in Alberta's social fabric by identifying socio-ecological possibilities in the province and making socio-ecological choices with its energy project decisions. The legal structure of Alberta's public land use decision-making framework channels debate over broad socio-ecological values into the Board's project review process. The language of ERCA s. 3, a key provision in the Board's governing legislation, acknowledges this important AEUB decision-making role, requiring the Board to consider the social, economic and environmental effects of an energy project in its decision.

¶ 34 In the Polaris Decision, the Board once again confirmed its view that ERCA s. 3 requires that it ask whether the benefits of the individual project exceed its immediate costs. With this narrow interpretation of ERCA s. 3, the Board avoided making a judgment as to the desirability of energy exploration in the Whaleback region. While the Board was presented with evidence from which to make a judgment concerning the broader implications of energy projects in the region, [See Note 65 below] the Board chose not to do so. The Board believes that the desirability of an individual energy project can be assessed apart from broad socio-ecological concerns.

Note 65: Polaris Applications No. 1276521 and 1276489, supra note 4.

¶ 35 Consistent with this, the Board maintains that the 1993 enactment of ERCA s. 3 simply confirmed the status quo. This view is particularly troublesome in light of the shortcomings of its narrow cost/benefit approach to considering the social, economic and environmental effects of an energy project. The Alberta Court of Appeal, as the reviewing body over AEUB decisions, has failed on two occasions to provide any insight as to how ERCA s. 3 should be interpreted. There is a glaring absence of judicial analysis explaining why it is sufficient for the AEUB to interpret its ERCA s. 3 mandate solely as a cost/benefit calculation; An interpretation that discounts non-measurable socio-ecological information without justification and adheres to an overly simplistic view that the human nature relationship can be described primarily as an allocation of economic benefits and ecological costs. The Board's current approach is, at best, an incomplete attempt to meet its ERCA s. 3 obligation.

* * *

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tion with interstate communications was through a physical connection with the dominant interexchange carrier serving the city.

5. CERTIFICATES, § 123 — Telecommunications service — Fiber-optic toll facility — When public interest hearing required.

[S.D.Sup.Ct.] Under S.D. Compiled Laws §§ 49-31-20 and 49-31-21, a telecommunications facility is exempt from a public interest determination if the facility is a nonaccess facility and the facility crosses the territory being lawfully occupied and served by another telecommunications company furnishing reasonably adequate service; a joint venture between a telephone cooperative and a municipality to build a fiber-optic toll facility between two cities was found to require a public interest hearing even though it had been previously ruled that none was necessary, because the facility did not extend across territory being lawfully occupied and served by another telecommunications company furnishing reasonably adequate service.

Berkeley Electric Cooperative, Inc. v. South Carolina Public Service Commission

No. 23340
402 S.E.2d 674

South Carolina Supreme Court
February 4, 1991

ORDER affirming electric utility's right to provide service to a business situated on land annexed by municipality, due to exclusive franchise agreement, despite location of business within 300 feet of competing electric cooperative's existing electric lines.

[ABSTRACT OF DECISION. THE FULL CASE TEXT IS OMITTED.]

1. MONOPOLY AND COMPETITION, § 28 — Division of service territory — Territorial Assignments Act — Municipal annexation.

[S.C.Sup.Ct.] The Territorial Assignments Act gives an electric utility the right to serve buildings located within 300 feet of its existing electric transmission lines, but applies only to areas assigned by the commission; thus, the Act reserved no rights to an electric cooperative with existing lines for an undeveloped corridor area that had been annexed by a municipality and made part of an exclusive municipal franchise agreement.

2. MONOPOLY AND COMPETITION, § 29 — Division of service territory — Franchise agreement — Municipal annexation.

[S.C.Sup.Ct.] A municipality may provide its own service within corporate limits, or it may designate a supplier through a franchise agreement and still prevent an existing electric utility from expanding its service into a newly annexed area.

3. MONOPOLY AND COMPETITION, § 29 — Division of service territory — Franchise agreement — Municipal annexation.

[S.C.Sup.Ct.] Where a municipality had granted an electric utility permission to serve land newly annexed by the municipality by terms of a pre-existing franchise agreement, that utility was entitled to continue providing electric service to a business on that land, even though the business was located within 300 feet of existing electric lines of another supplier.

4. WITNESSES, § 4 — Qualification as expert — Trial judge discretion — Probative value.

[S.C.Sup.Ct.] The qualification of a witness as an expert in a particular field is within the sound discretion of the trial judge, and where the expert's testimony is based upon facts sufficient to form the basis for an opinion, the trier of fact determines the probative value.

Re Biennial Resource Plan Update Following the California Energy Commission's Seventh Electricity Report

Decision No. 91-06-022
I.89-07-004

California Public Utilities Commission
June 5, 1991

ORDER approving modifications to standard offers used by electric utilities to purchase electricity from qualifying cogeneration and small power production facilities (QF). The modifications initiate a program by the commission to incorporate non-price factors, such as environmental externalities, in determining appropriate levels of QF development, and eventually to develop a system of "environmental least cost" resource planning.

1. MONOPOLY AND COMPETITION, § 54 — Electric — Generation market — Transmission bottleneck — Nonprice factors.

[CAL.] To promote the establishment of a fully competitive market for electric generation the commission found that it must: (1) ease the transmission bottleneck; (2) require accurate evaluation of resource options, including identification of "nonprice" factors such as fuel diversity and environmental quality; and (3) expand the eligibility to bid on utility power requirements to all supply sources.
p. 186.

2. MONOPOLY AND COMPETITION, § 54 — Electric — Generation market — Wheeling.

[CAL.] Wheeling of electric power by electric utilities is critical to achieving a fully competitive generation market; the terms of wheeling service must ensure both that the wheeling utility gets reasonable compensation and that it cannot use its control of bottleneck facilities to extract monopoly rents.
p. 186.

3. COGENERATION, § 17 — Contracts — Non-price factors — Fuel diversity — Environmental quality.

[CAL.] While reviewing standard offers employed by electric utilities in purchasing power from qualifying cogeneration facilities, the commission initiated a program to establish a quantitative basis for weighing nonprice factors, such as fuel diversity and environmental quality, in determining the value of particular resource options.
p. 187.

4. COGENERATION, § 24 — Rates — Standard offer contract — All-source bidding — Market status.

[CAL.] While finding that "all-source bidding" was a necessary component of a fully competitive market for electric generation, the commission decided that a special market category was still required for qualifying cogeneration facilities (QFs) until such time as structural changes in the market were in place to make the marketplace truly competitive; such changes would include easing the transmission bottleneck and equalizing market power among utility and non-utility producers.
p. 188.

5. ELECTRICITY, § 4 — Generating plants — Efficiency — Least cost planning program — Environmental quality — Fuel diversity.

[CAL.] The commission revised its electric resource planning policies to allow for consideration of both environmental and fuel diversity values in comparing resource options in both the planning and acquisition portions of the resource procurement process; while deferring consideration of specific methods for the quantification of fuel diversity values, the commission adopted specific values for air quality based on the residual emissions (those remaining after application of control technologies) of various resource options.
p. 188.

6. ELECTRICITY, § 4 — Generating plants — Efficiency — Least cost planning program — Environmental quality — Fuel diversity.

[CAL.] Values assigned to fuel diversity

and environmental effects under revisions to the commission's least cost planning program should affect both the planning and acquisition portions of the resource procurement process; accordingly the commission found that the values would apply to the identification of deferrable resources and to energy payments made to winning bidders under the commission's standard offer auction for qualifying facilities.
p. 188.

7. ELECTRICITY, § 4 — Generating plants — Efficiency — Least cost planning program — Environmental quality — Fuel diversity.

[CAL.] Power plant emissions impose costs on society including measurable impacts on productivity at work, enjoyment of leisure, and human life spans; such costs must be accounted for in the least cost planning process.
p. 194.

8. ELECTRICITY, § 4 — Generating plants — Efficiency — Least cost planning program — Environmental quality — Fuel diversity.

[CAL.] Least cost planning principles must assign a value to fuel diversity because fossil fuels, while currently cheap and plentiful, are not renewable and are subject to price fluctuations as well as environmental problems; a truly least cost electric resource procurement strategy would hedge against the short- and long-term risks of reliance on fossil fuels by diversifying the generation mix to encourage the development of alternative and renewable technologies.
p. 194.

9. ELECTRICITY, § 4 — Generating plants — Efficiency — Least cost planning program — Environmental quality — Fuel diversity.

[CAL.] Valuation of the environmental costs of various resource options available to an electric utility was based on the system to be served rather than the site of the power plant; such a method is consistent with the traditional ratemaking system under which revenue requirements and rate design are determined on a systemwide basis rather than on the basis of either the location of either facilities or communities.
p. 196.

10. ELECTRICITY, § 4 — Generating plants — Efficiency — Least cost planning program — Environmental quality — Fuel diversity — Set asides.

[CAL.] In initiating a method to quantify the value to electric utilities of fuel diversity, the commission found that a system of quantitative values applied to each resource option as part of the planning and procurement process was preferable to a system of set asides for non-fossil bidders.
p. 197.

11. ELECTRICITY, § 4 — Generating plants — Efficiency — Least cost planning program — Environmental quality — Fuel diversity — Emissions offsets.

[CAL.] Air emissions offsets acquired by power plant operators under state and federal environmental statutes were included in a new electric least cost planning program designed to reflect nonprice factors such as environmental quality and fuel diversity, in the resource procurement process.
p. 198.

12. COGENERATION, § 24 — Rates — Standard offers — Renewable and alternative fuels.

[CAL.] The existing standard offer approved by the commission for the purchase of power by electric utilities from qualifying cogeneration facilities was modified to cure a competitive bias against capital intensive projects such as renewable or alternative fuel projects; the modifications included: (1) extending the length of the standard offer contract from 15 years to a flexible term based on the life of the individual project and (2) removal of the total exclusion of front-loaded pricing schedules.
p. 200.

13. COGENERATION, § 24 — Rates — Standard offers — Capacity and energy bidding.

[CAL.] The commission revised its cogeneration standard offer rules to require all qualifying facilities (QFs) to bid capacity and energy prices separately, thereby allowing both fossil

and non-fossil QFs equal opportunity to provide their full fuel diversity and efficiency benefits to ratepayers.
p. 202.

14. COGENERATION, § 24 — Rates — Standard offers — Bidding process — Second price auction.

[CAL.] While revising its standard offer rules for power purchased by electric utilities from qualifying facilities (QFs), the commission rejected a proposal by the utilities to allow payment of winning bid prices to each QF; the commission found that the principles supporting its adoption of full avoided cost pricing for QFs also applied to its choice of auction format and that the current "second price auction" better served those principles.
p. 207.

15. ELECTRICITY, § 4 — Generating plants — Efficiency — Least cost planning program — Environmental quality — Fuel diversity — Avoided cost benchmark — Utility built projects.

[CAL.] While reviewing its policies governing electric utility least cost planning and resource acquisition, the commission ruled that it would not treat the avoided cost benchmark rate established for qualifying facility standard offers as a binding cost estimate on the utility should it decide to build what had been identified as the deferrable resource for QF pricing purposes.
p. 213.

16. ELECTRICITY, § 4 — Generating plants — Efficiency — Least cost planning program — Environmental quality — Fuel diversity — Resource plan.

[CAL.] To guarantee the integrity of the resource bidding process approved by the commission for power purchased by electric utilities under standard offers from qualifying cogeneration facilities, resource decisions made by the utilities between Biennial Resource Plan Updates must be consistent with the assumptions and policies used in formulating the resource plan; the commission rejected proposals to increase current constraints on purchases between updates and proposals to establish price thresholds to provide assurance of reasonableness for such purchases.
p. 215.

17. COGENERATION, § 24 — Rates — Standard offers — Firm requirements — As-available requirements.

[CAL.] The commission rejected a proposal to prevent qualifying cogeneration facilities who bid for as-available requirements (Standard Offer 1) from bidding for firm requirements (Standard Offer 4) where it found that full participation in the firm requirements second-price auction could result in a lower price to all successful bidders.
p. 218.

18. ELECTRICITY, § 4 — Generating plants — Efficiency — Least cost planning program — Environmental quality — Fuel diversity — Demonstration projects.

[CAL.] The commission rejected a proposal to establish special rules under its electric resource acquisition program for non-utility research and development demonstration projects finding that many special contracts had been approved in the past despite the existence of a standard offer system for qualifying facility producers and that the proposed changes might allow demonstration projects to defer other resources.
p. 219.

19. ELECTRICITY, § 4 — Generating plants — Efficiency — Least cost planning program — Environmental quality — Fuel diversity.

[CAL.] While reviewing its policies governing electric utility least cost planning and resource acquisition the commission found that uncertainty should be considered explicitly in the planning process by quantifying known risks and including strategic elements into the resource plan to respond to those risks.
p. 220.

20. COGENERATION, § 24 — Rates — Standard offers — Long-run versus short-run pricing.

[CAL.] While finding that the "Standard

Offer 4" for firm purchases of energy and capacity by electric utilities from qualifying cogeneration facilities (QFs) should be the primary instrument for QF involvement in the resource procurement process, it refused to eliminate the possibility that it might reinstate the short-run "Standard Offer 2" for a limited time during the development of a satisfactory long-run offer.
p.222.

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i. MONOPOLY AND COMPETITION, § 54 — Electric — Cogeneration — Auction format.

[CAL.] Discussion by the commission while reviewing its policies governing electric utility least cost planning and resource acquisition concerning the nature of competitive markets in general and how market principles would apply in choosing an appropriate auction format for bids by qualifying facilities.
p. 207.

ii. ELECTRICITY, § 4 — Generating plants — Efficiency — Least cost planning program — Environmental quality — Fuel diversity — All-source bidding.

[CAL.] Statement by the commission while reviewing its policies governing electric utility least cost planning and resource acquisition that it intended to move toward all-source bidding, but that such a move depended upon making significant progress in evaluating nonprice factors and in allowing nondiscriminatory access to transmission services for nonutility power producers.
p. 214.

APPEARANCES: (See Attachment 5 in Decision 90-03-060 for appearances.) *Additional Appearances:* Marron, Reed & Sheehy, by *Emilio E. Varanini III,* for Texaco Syngas Inc; *David R. Stevenson*, for Chevron U.S.A. Inc.; *William Meckling*, for Recon Research Corporation; and *Daniel Kirshner*, for Environmental Defense Fund; interested parties.

Before Eckert, president, and Wilk, Ohanian, Fessler, and Shumway, commissioners.

BY THE COMMISSION:

I. *Summary of Decision*

In today's decision, we order several changes to final Standard Offer 4 and other standard offers created in the consolidated Application (A.) 82-04-44 et al. Specifically, we begin the task of incorporating consideration of non-price factors, such as environmental impacts, in determining appropriate levels of Qualifying Facility (QF) development. Our goal is to arrive at what has aptly been called "environmental least cost" resource planning.[1]

We also order certain adjustments to the payment and bidding structure of final Standard Offer 4. These adjustments are designed to ensure fair competition between different generation technologies and to promote economic dispatch of utility resources by providing accurate price signals regarding QFs' running costs.

II. *Background*

A. *The Role of the Update*

Today's decision is the second major step in the current Biennial Resource Plan Update (BRPU or Update). In the BRPU, we revise long-term forecasts and address generic issues related to utility purchases of electricity from a broad class of nonutility energy producers, called "qualifying facilities" or "QFs." Our regulation of these purchases relies on two concepts: avoided costs (as to the purchase price) and the standard offer (as to the contractual relationship).

Avoided costs represent the costs a utility would incur, if not for the presence of QFs, to generate power itself or purchase it elsewhere. The standard offer is an open utility offer to purchase electricity from a QF, on terms and conditions stated in the offer. The contract terms of the offer are developed from guidelines adopted by this Commission. Over the past ten years, we have refined and implemented these

concepts in a series of decisions. (See Attachment 2.)[2]

The BRPU provides us with an industry-wide forum for continuing our regulatory oversight of utility/QF matters. A major purpose of the BRPU is to update the prices for final Standard Offer 4, our resource plan-based standard offer. This involves quantifying the megawatts (MWs) that QFs can fill on the basis of each utility's need for new capacity. Each two-year Update cycle commences upon issuance of the California Energy Commission's (CEC) Electricity Report.

The BRPU is also the forum for updating certain components of QF payments that affect our short-run offers, Standard Offers 1, 2, and 3.[3] In Decision (D.) 88-09-026 (29 CPUC 2d 263 [1988]) and D.89-02-017 (31 CPUC 2d 13 [1989]), we also directed parties to address issues relating to Standard Offer 2 availability in this Update. Finally, each BRPU provides a forum for considering changes in methodology or contract terms for all of our standard offers.

B. *How Final Standard Offer 4 Works*

Before discussing the issues resolved in today's decision, we summarize briefly the structure created for final Standard Offer 4 in D.86-07-004 (21 CPUC 2d 340, 76 PUR4th 1 [1986]). Unlike our short-run standard offers, final Standard Offer 4 derives from a utility's long-run marginal costs. These are determined from the respective utility's resource plan, which includes all cost-effective potential generation additions (e.g., new plant construction, refurbishments, power purchases, etc.).[4] Payments to QFs under the long-run offer are based on the fixed and variable costs of those additions that serve as baseload or intermediate-load resources. Such additions are called "identified deferrable resources" (IDRs).

Pricing under final Standard Offer 4 varies according to when the QF comes on-line. During Period 2, the QF avoids a specific utility resource addition, and the QF receives payments based on the fixed and variable costs of the avoided resource. If the QF comes on-line in Period 1, i.e., before the date when the avoided resource would have begun delivery of electricity, the QF meets near-term demand growth, and therefore the QF receives short-run marginal cost-based payments until the start of Period 2.

The Commission considers alternative scenarios for each utility in determining a MW limit at each Update. Whenever the capacity of QFs seeking contracts from a given utility exceeds that utility's MW limit, the available contracts are allocated through bidding. The utilities are also authorized to pay QFs additional sums for providing performance features (e.g., downward dispatchability at the utility's direction) not otherwise required under the standard offers. Attachment 4 presents a more detailed chronological overview of the final Standard Offer 4 updating process.

C. *Phasing of the Issues*

BRPU is a phased proceeding in which general methodological issues for the standard offers are treated separately from the resource plan review to determine whether the utilities have long-term resource needs that should be put up for bidding by QFs. We began this Update in response to the CEC's 1988 Electricity Report. In Phase 1A, we adopted certain planning assumptions for this Update and resolved certain generic issues over what constitutes a "committed" resource (not subject to deferral or avoidance by QFs) and how to test resources for cost-effectiveness. (D.90-03-060, 36 CPUC 2d 2 [1990].)

The current phase (Phase 1B) was intended to be the resource plan review. However, by Administrative Law Judge's (ALJ) Ruling of June 13, 1990, the schedule was changed. The ALJ noted that the 1988 Electricity Report, which had been issued late, would be superseded shortly by the 1990 Electricity Report (ER-90). Assuming the CEC met its deadline for fall issuance of ER-90, the base case planning assumptions from the earlier report would be outdated before Phase 1B could be completed.[5] Thus, the ALJ ruled that the utilities should make their resource plan filings using data from ER-90. These filings will now follow Phase 1B.

This change has enabled us to use Phase

1B to consider refinements to the standard offers that could be implemented in time for any QF auction resulting from ER-90. Specifically, we wanted to ensure that our QF procurement process was well-suited to all of the different electric generation technologies and did not have a built-in bias toward gas-fired resources. Also, we wanted to enhance that process in order to value non-price factors, such as environmental impacts and fuel diversity, in planning and acquiring new resources. We also entertained proposals for change to the bidding protocol.

We indicated that any proposed change to these aspects of final Standard Offer 4 could be considered, subject to the following criteria:

1. The approach for establishing MW for purposes of the QF auction must continue to rely on the identification of deferrable resources, based on evaluating the cost-effectiveness of a utility's resource plan; and

2. The changes must be of a reasonable scale and fully elaborated, such that they could be reviewed, adopted, and implemented by year-end.

We also asked for comment on the following issues:

1. How should this Commission use the ER-derived base case in its determination of deferrable resources? How, if at all, should the current procedure for considering uncertainty and strategic preferences be modified?

2. Now that final Standard Offer 4 has been completed, what is the role of Standard Offer 2, which contains fluctuating energy prices but fixed capacity prices? How and when should Standard Offer 2 be reinstated?

3. What restrictions, if any, should be placed on utilities' ability to commit to long-term power purchases between Updates?

In the following sections, we summarize the parties' positions and discuss our conclusions on these issues.[6] As usual in such proceedings, the record is voluminous.[7] We concentrate on the chief points of contention, and do not try to summarize every nuance in individual positions. We apologize for this but believe that the saving of space and the gain in clarity justify using an overview.

III. *Toward a Fully Competitive Market in Electric Generation*

[1] The issue in Phase 1B is not over where to go but how to get there. All parties support increased competition among potential suppliers of electricity to California; they differ on ways to achieve that result.

We discuss below three further steps that we must take to arrive at our goal of a fully competitive market in electric generation. All three steps are necessary, but the sequence is important. The first two must precede the third, or we put all our progress to date in jeopardy.

A. *Easing the Transmission Bottleneck*

[2] Now and through most of the 1980s, the competition to serve new demand in California has largely been between California utilities and QFs. QF generation as a percentage of power plant capacity in California has grown during that period from a negligible level to about 12% of current dependable capacity. (See ER-90, page 3-3.)

This growth in QF capacity does not mean that workable competition exists in the California electric generation market. The growth has occurred in part because utilities are now legally required to interconnect with QFs and to buy their output under terms and conditions supervised by this Commission. Before the 1980's, the utilities had not aggressively pursued alternative generation technologies or contracts with small power producers.

Much of the utilities' market power in relation to QFs comes from utilities' control over transmission. For the foreseeable future, the transmission sector of the electric industry will remain a natural monopoly. This means that, with utilities controlling the bottleneck facilities, QFs have only such access to the wholesale market as the interconnecting utility is willing to provide. Unless the QF can get the interconnecting utility to transmit ("wheel") the QF's output to other buyers, the interconnecting utility has a virtual monopsony over QFs in its service area.

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Wheeling is critical to achieving a fully competitive market in electric generation. Fully competitive markets have many buyers, many sellers, with ready access to each other. To compete to serve a potential buyer, the QF must have reasonable assurance of the cost and other terms under which it may have its output wheeled to that buyer. The terms of wheeling service must ensure both that the wheeling utility gets reasonable compensation and that it cannot use its control of bottleneck facilities to extract monopoly rents.

In a parallel proceeding (I.90-09-050), we are considering both transmission cost allocation issues for the utility buying nonutility power and possible terms and conditions for nonutility power producers that require transmission-only service from a utility. We expect significant progress in that investigation during this ER/BRPU cycle.

B. *Evaluating Resource Options*

[3] Along with opening up the avenues of competition (the transmission network), we still have much work to do on the bases of competition in the electric industry. In other words, what are the best electric resource options, considering all the features that make an option more or less valuable? This question affects the entire resource procurement process, including both planning (defining the IDR) and acquisition (building the IDR or finding superior alternatives).

The current auction selects winners by comparing the bidder's offered price to what it would cost the utility to build and run the IDR. The current auction does *not* consider what are generally called "non-price factors." These factors may be defined as things associated with power plant operation that affect the value to society of the electric power but that are not usually accounted for in the capital and operating costs incurred by the power producer or in the price paid for the electricity. One example of a non-price factor is whether the bidder (compared to the IDR) will lessen, increase, or have no effect on our dependence on fossil fuels. Another example is whether the bidder (compared to the IDR) will improve, harm, or have no effect on our environmental quality.

Fuel diversity and environmental quality have long had a significant role in discussion of electric resource strategies both here and at the CEC, but until today's decision we have not established a quantitative basis for weighing these non-price factors in determining the value of particular resource options. Without such quantification, we limit the ways in which different options can compete and increase the likelihood that some of the chosen options, when all factors are considered, provide less value than some that were rejected.[8]

Most of our discussion deals with electric *supply* options (i.e., new generation) for meeting future demand. It is also possible to slow demand growth and stretch current supply through conservation, shifting load off-peak, improving the energy efficiency of appliances and buildings, and other kinds of demand-side management (DSM). We need to improve the way we account for the value of DSM to ensure a fully competitive resource procurement process. Current analysis may undervalue DSM in some respects and does not handle supply options and DSM in the same way.

First, like QFs, the value of DSM is better appreciated when non-price factors are taken into consideration. Quantitative analysis of these factors should produce better-informed judgments on the value of DSM in the electric resource mix.

Second, we now use different methods to analyze the cost-effectiveness of supply options and DSM. For supply options, both the California Public Utilities Commission (CPUC) and the CEC use the iterative cost-effectiveness method (ICEM); for DSM, both agencies use the Standard Practice Manual for the Economic Analysis of Demand-Side Management Programs. The differing methods for quantitative analysis thwart efforts to directly compare supply options with DSM. They also give rise to charges that the CPUC is trying to shield its QF program from competition, or that the CEC is trying to shield its DSM programs from competition.

We are committed to head-to-head comparison of DSM and supply options in the planning process, and perhaps ultimately in the bidding process as well. To get there, we need to test the capabilities of our analytic tools.

SDG&E has completed a pilot program using ICEM to integrate DSM into its resource plan. The SDG&E pilot has received peer review, and SDG&E indicates that it will use its pilot, with modifications, in presenting its ER-90 resource plan in the next phase of the BRPU. Meanwhile, PG&E and Edison will conduct their own pilot programs using ICEM and present their conclusions in workshops during 1991. These efforts should illuminate what factors are involved in directly comparing DSM and supply options, and the advantages and limitations of ICEM in making that comparison.

C. *Expanding Eligibility to Bid*

[4] The final Standard Offer 4 auction is now limited to QFs. The utilities can and do sign power purchase agreements outside the auction with QF and other sellers, but everyone recognizes that arm's length competition in a single arena open to all potential suppliers is likely to result in the most attractive bids. The name for this is all-source bidding, and we agree in principle with the many parties that support all-source bidding as a necessary component of a fully competitive resource procurement process. But there are two compelling reasons why we are not yet ready for all-source bidding.

First, we are still opening up the avenues of competition and establishing the bases of competition, as we've just discussed. Those tasks are under way but far from finished, and until those tasks are done, new QF projects are fundamentally disadvantaged in the marketplace. They have no assured access to utilities acquiring resources, nor is their full resource value likely to be recognized. Under these circumstances, opening the auction to non-QF entities irrespective of the market power such entities may have will weaken competition, not increase it.

Second, the QF category has not outlived its usefulness. The Federal Energy Regulatory Commission (FERC) developed this category in its regulations implementing PURPA. The category responds to the aims that PURPA embodies. QFs are not themselves public utilities, and the regulations limit the amount of equity that a utility may have in a given QF. QFs are limited in size. They must use renewable or alternative fuel sources, or meet certain efficiency standards if they use fossil fuels.

In short, QFs are the kind of entity that was essentially frozen out of the pre-PURPA electricity market. Utilities and other entities controlled by utilities have always participated in that market. The auction does not prevent them from doing so now, but it does reserve a market niche that QFs can bid to obtain. Until we have taken the steps discussed earlier, such a niche is necessary and appropriate.

Arguments that the QF industry has grown or that it includes large corporations are beside the point. The relevant question is whether the underlying market structure has changed so that future QF projects can compete fairly. We find that it has not. The successful addition of 1,000s of MW of QF capacity in the past decade is impressive, but it does not justify abandoning the QF program, any more than do the strides already made in energy efficiency justify neglecting DSM.

IV. *Evaluating Environmental Quality and Fuel Diversity*

A. *Introduction*

[5, 6] There was little consensus on this topic, so we will go through the parties' positions in some detail. However, we begin by describing the approach we are adopting in today's decision. This approach follows directly from policies consistently applied since our earliest decisions (D.85-07-022 [18 CPUC 2d 333, 68 PUR4th 1 (1985)] and D.86-07-004 [21 CPUC 2d 340, 76 PUR4th 1 (1986)]) on final Standard Offer 4.

We adhere to our policy of allowing competition by all technologies, without setting aside any given amount of capacity for non-fossil technologies to further environmental or fuel diversity goals. We recognize the importance of those goals, and in Section V below we make certain changes to the final Standard Offer 4 bidding and payment structure where current provisions were inappropriate for non-fossil technologies or directly favored oil/gas-fired resources. In this section, we are modifying our resource planning and acquisition process so that environmental and fuel diversity values appropriately figure in that process.

Specifically, ICEM will henceforth reflect the "residual emissions" (those remaining after application of appropriate control technology) associated with the operation of any resource being tested for cost-effectiveness. The (negative) value of such emissions will be determined using the principle of "revealed preference," which means that the costs imposed by relevant regulatory agencies, for example, in requiring certain pollution abatement actions, will be analyzed to calculate the implicit monetary value assigned to avoid a given quantity of a given pollutant.

These values will apply to the identification of deferrable resources and (as adders or subtractors) to energy payments made to winning bidders. In other words, residual emissions will figure throughout the procurement process, that is, in both the planning and the acquisition of new resources. If any "offsets" (purchased reductions of emissions from existing sources of pollutants) are associated with the deferrable or bid resource, the impact of such offsets will also be included.

For the time being, we will only consider air quality values, but we firmly believe that residual impacts on water and land use must not be neglected. We expect progress in these areas, particularly water use, in future Updates and Electricity Reports.

We have not adopted a method for valuing fuel diversity at this time. Some non-fossil IDRs, because they are generally "clean" technologies, are likely to appear simply through inclusion in ICEM of residual emissions. Should that not occur, we direct the utilities to impute additional value to non-fossil resources until non-fossil IDRs appear as the first addition during the next eight years in their resource plans. This will effectively quantify the size of any premium necessary to secure non-fossil IDRs. We will decide in the next Update phase whether any such premium is reasonable. We also encourage further work in future ER/BRPU cycles to adapt portfolio theory and other tools for quantitative evaluation of fuel diversity.

B. *Background*

ER-90 made major advances over prior California resource planning efforts in its approach to environmental quality and fuel diversity. All parties agree that these factors should affect an electric utility's choices in meeting future demand on its system, but there is little agreement on how the utility should take them into account.

Part of the difficulty is that these factors' impacts on utility costs and society are not easy to calculate. The value of fuel diversity depends on assessing the financial risks of relying too much on a given fuel, and on calculating how best to insure against those risks. As for environmental quality, the producers (including utilities) that create pollution have generally not had to bear all the costs of pollution but have instead "externalized" a substantial part of those costs to society as a whole. The utilities logically should bear their fair share of such costs, although the size of that share is debatable.

For purposes of this discussion, acquiring "fuel diversity" for California utilities means increasing the proportion in their resource mix of electricity generated by plants that do not rely on oil, coal, or natural gas as their primary fuel source. Some technologies burn small amounts of natural gas, e.g., gas-assisted solar. A power plant using such a technology would still be considered non-fossil if it uses natural gas for no more than 25% of its total energy input during a calendar year.[9]

"Environmental quality" includes air, water, and land use considerations. Most parties would limit evaluation efforts during this ER/BRPU cycle to air quality impacts.[10] The reason for the limitation is that the analysis of air quality impacts has been spurred by recent state and federal clean air legislation and actions by local air management districts. California utilities, along with other major sources of air pollutants, are facing major clean-up costs now or in the near future. Air basins in California must now achieve annual reductions in total emissions of specified air pollutants, and this will inevitably affect how each electric utility plans and operates its system.

The imminence of these air quality problems convinces us that the priority given to evaluation of air quality impacts is appropriate. However, all Californians know that the state has a water crisis. Environmental review during the permit process for new power plants should ensure that the plants have acceptable environmental impacts, but only if water is included along with other environmental considerations in procuring new generation will a power plant project that preserves our water resources be able to use that fact to competitive advantage. We urge that power plant impact on water resources be further examined in the next ER/BRPU cycle.

C. *Air Quality Overview*

The following discussion serves chiefly to introduce some terms and concepts that are inevitable when relating air quality to electric generation.

Ambient air quality standards (AAQS) apply to a rogue's gallery of hazardous substances. These "criteria pollutants" include certain sulfur/oxygen compounds (SOx), carbon monoxide, lead, particulate matter in suspension (PM), a group collectively referred to as reactive organic gases (ROG), and ozone, which is a principle component of smog. Nitrogen/oxygen compounds (NOx) are "precursors" (through chemical reactions in the atmosphere) to criteria pollutants, and also contribute to acid deposition, a non-criteria pollutant.[11] Carbon dioxide is also considered a pollutant because it is a "greenhouse" gas and so contributes to possible global warming.

Concentrations of criteria pollutants in excess of AAQS are unhealthy. When the concentration of a given criteria pollutant in an air basin regularly violates AAQS, the air basin is designated a non-attainment area. PG&E, SDG&E, and Edison all serve major metropolitan areas that are also non-attainment areas.

California is moving aggressively to address its air quality problems. Beginning in 1988, the California Clean Air Act requires that local districts reduce emissions of non-attainment pollutants or their precursors by 5% per year (by air basin). Local districts are required to develop new air quality attainment plans to meet [AAQS] by December 1991. These plans include more restrictive emissions limitations for existing sources and new procedures for permitting new sources." ER-90, page 5-4 (footnote omitted). These requirements also apply to districts that are themselves in attainment but that contribute to attainment problems downwind.

Air management districts have the ability to require retrofits of power plants as part of these plans. Also, air management districts may require new sources to apply the best available control technology (BACT). SCAQMD has taken both of these actions to deal with NOx emissions. Proposed Rule 69 of the San Diego County Air Pollution Control District would apply a more stringent NOx emission standard than SCAQMD's and would cover virtually all utility electrical turbines and boilers in the district. ER-90 assumes that NOx retrofit requirements will be adopted in both San Diego and Ventura Counties.

New sources may also have to acquire "offsets" of any residual emissions after application of BACT by arranging to reduce emissions from an existing source. Specifically, regulations of the federal Environmental Protection Agency require that all increases in emissions resulting from a major new source must be mitigated by the *permanent* reduction of emissions from existing sources. "Offset requirements are administered by local air districts and are set on a site-specific basis." (ER-90 at page 5-7.) Air management districts in non-attainment areas may require such offsets in a ratio greater than one-to-one. This is the case with the San Francisco Bay Area (1.1:1), Los Angeles (1.2:1), and San Diego (1.2:1) air basins.

Many of the pollutants mentioned above are produced when fossil fuels are burned. In particular, burning oil and gas will produce NOx. The CEC notes that in its ICEM analysis, NOx was the only pollutant whose value actually affected the timing of new resources, and NOx accounted for almost half the total value attributed to residual emissions.[12]

D. *Positions of Parties*

Every party favors accounting of some sort for environmental quality and fuel diversity in the resource procurement process. No two parties agree on how to do this. Major issues include the following:

- Should such accounting occur through quantitative analysis (for example, attaching monetary values to the impacts) and/or policy judgments? If monetary values are used, how should they be derived?
- Where should such accounting be done: in planning (selection of IDRs), in acquisition of resources (designation of auction winners and setting final Standard Offer 4 prices), or in both?
- If monetary values are assigned to environmental impacts, should the values be the same regardless of the location of the projects and IDR being compared, or may the values differentiate between projects (and IDRs) inside, and outside the acquiring utility's service area?
- Should there be a set-aside or separate bidding arena or a premium for non-fossil QFs, and if so, should there be a cap on the amount by which payments to such QFs might exceed payments to oil/gas-fired QFs?
- Should the valuation of IDRs and bidders take account of offsets?

1. *PG&E*

PG&E proposes a set-aside for non-fossil and renewable resources as an interim measure to deal with the issues of global warming and fuel diversity. However, environmental values should not be incorporated into the need determination for Northern California.

PG&E's set-aside involves two bidding arenas, one of which would be limited to non-fossil resources. The other arena would be open to all resources. Half of identified need (up to 400 MW, nameplate) would be allocated to the non-fossil arena. In each bidding arena, winners would be determined on the basis of benefit/cost (B/C) ratio. PG&E would allow the set-aside bidders to have a lower B/C ratio than oil/gas-fired bidders, provided the former have B/C ratios of at least 1.0 *or* (if less than 1.0) at least 80% of the lowest winning ratio in the all-technologies arena. PG&E believes that the MW cap and reduced B/C threshold should change over time as circumstances change, such as new or more stringent emissions restrictions.

PG&E believes that NOx adders for bid selection would create a windfall for developers at ratepayer expense. An adders system is not compatible with emissions offsets, according to PG&E. Values of offsets differ between Northern California and Southern California, so the value assigned for Northern California should not be the same as the SCAQMD value. The amount of NOx emission reduction needed in Northern California is unknown, so SCAQMD goals don't apply to Northern California.

PG&E believes the marginal cost of reducing NOx emissions depends on the degree of NOx emissions reductions needed. Assigning value to NOx emissions in ICEM increases the need for new generating resources in a situation which is already biased toward gas-fired plants. PG&E believes increasing this alleged bias is contrary to Public Utilities Code § 701.1, which requires the CPUC to look at all practicable and cost-effective conservation and improvements in the efficiency of energy use."[13]

2. *SDG&E*

SDG&E opposes set-asides and proposes instead a two-phase multi-attribute bidding system where NOx emissions and dispatchability are valued in the first phase, followed by a negotiation phase in which any and all other factors (emissions other than NOx, other environmental impacts, fuel diversity, operational considerations besides dispatchability, project viability, flexible start date, et al.) might be weighed by the utility. The bidder would *not* know in advance the values placed by the utility on attributes in the negotiation. (This distinguishes the SDG&E auction from the "transparent" auction, supported by all other parties, in which bidders know in advance how winners will be determined.)

SDG&E recommends that residual emission values not be included in the planning stage (ICEM analysis) at present due to uncertain ratepayer impacts. SDG&E recommends valuing emissions only in resource acquisition.

SDG&E would incorporate environmental factors into the bidding system using conservative "starting point" values as in the Pace University Study. If the IDR requires emission controls or offsets, those costs are included in the IDR costs. Offsets should be valued at the cost to obtain those offsets, which in turn is related to the cost of the technologies applied to control the various emissions.

SDG&E believes set-asides are unnecessary because reasonable values exist for air quality benefits, and the record does not prove that set-asides are a good proxy for fuel diversity.

3. *Edison*

Edison opposes the set-aside approach. Edison advocates a transparent auction and direct quantification of environmental attributes and fuel diversity in the acquisition but not in the planning portion of the resource procurement process.

The quantification Edison supports would use positive or negative adjustments to the projected costs of the IDR.[14] Specifically, Edison would impute an extra 15% to the projected energy costs of the IDR if it is oil/gas-fired (or a substantially higher premium if the IDR is coal-fired) and use the adjusted costs in evaluating the benefits of a non-fossil bidder. If the IDR uses an existing site and the bid project requires development of a new site, 15% would be deducted from the capital portion of the IDR.

According to Edison, using a set-aside is an admission that non-price attributes cannot be quantified and that renewables cannot compete head-on with other technologies. Edison believes the amount of MWs set aside for renewables is an arbitrary number. If a set-aside is adopted, Edison believes the price cap should not be set by a renewable resource, and the size of the set-aside should be determined after examining ratepayer impacts.

4. *TURN*

TURN believes ICEM should not be modified to incorporate values for residual air emissions. TURN asserts the record contains no information on the rate impacts of valuing residual emissions in ICEM. Public Utilities Code § 701.1 does not require inclusion of residual emission values in ICEM, just consideration in the resource procurement process. The value of residual emissions remains disputed.

TURN believes the amount of renewables that each utility acquires is a policy choice which is best made explicitly through the use of a set-aside. TURN believes that an adders approach is likely to increase ratepayer cost without necessarily resulting in the acquisition of renewable resources. TURN supports PG&E's approach for linking a set-aside with a price cap.

5. *CEC*

According to the CEC, environmental values should be used in planning but *not* in the acquisition portion of the resource procurement process. The CEC supports set-asides to secure fuel diversity, not environmental benefits. The CPUC should authorize the use of set-asides where the CEC's need assessment indicates a set-aside is appropriate. The CEC's set-aside recommendations are based on a utility-by-utility assessment of need. Precise valuation of fuel diversity is impossible at this time.

The CEC endorses the PG&E price cap approach as acceptable for implementing ER-90's set-aside recommendations, although PG&E concedes that the approach may not result in the acquisition of any non-fossil resources, let alone the proportion of non-fossil resources specified in ER-90. The CEC supports PG&E's multi-attribute approach but opposes DRA's adders proposal. The CEC asserts that adders do not accurately account for the effects of offsets and conflict with fuel diversity goals.

Also, the CPUC should adopt the CEC's ER-90 values for residual emissions for Edison.

No values for residual emissions should be adopted for SDG&E and PG&E at this time. Including values for residual emissions in ICEM is a reasonable method to incorporate air quality benefits and costs in resource planning. ER-90 shows that incorporating air quality values in ICEM is workable and reduces total emissions. The ER-90 approach is consistent with Public Utilities Code § 701.1, which encourages the CEC and CPUC to use consistent values for environmental factors.

6. *SCAQMD*

SCAQMD supports incorporation of environmental considerations throughout the resource procurement process. The appropriate value for residual emissions in Edison's service area is the marginal cost of control as revealed by BACT for NOx, ROG, SOx, and PM. SCAQMD also supports valuation of carbon dioxide emissions.

The CPUC should value residual emissions in its resource procurement process through use of adders. This method should reflect the valuation of air quality characteristics of a QF compared to the IDR on a regionally specific basis, where the value of emission reduction is tied to the cost of control for specific pollutants. The CPUC should value emissions in the payments to winning QFs; this allows a less polluting bidder to get a price advantage which reflects its environmental benefits. SCAQMD recommends not including the impacts of offsets in the calculation of adders.

The CPUC should establish a separate bidding arena for non-fossil resources in addition to incorporating environmental considerations into ICEM and QF payments. SCAQMD finds PG&E's set-aside does not ensure the acquisition of renewable resources.

7. *DRA*

DRA proposes that all costs associated with environmental impacts be included in both the planning and acquisition stages of the resource procurement process for each utility. DRA's adders proposal allows incorporation of offsets. DRA proposes a 10% fuel diversity premium.

DRA recommends that monetary values for residual emissions be factored into the ICEM analysis used to determine the least cost resource plan and the IDR(s). The monetary values of particular emissions are established and published before the auction. The values for residual emissions are based on BACT.

An adder (or subtractor) is based on the net difference in emission rates between the IDR and the bidder's project, multiplied by the value of residual emissions. The bidder takes the adder (subtractor) it would receive into account when determining its bid, but the adder (subtractor) is applied to the contract energy price only after the winner is selected.

DRA would take offsets into consideration when valuing a QF relative to the IDR. In a situation without offsets, the net difference in value is readily calculated from the difference in emission rate between the IDR and the QF. If the QF has a lower emission rate, it would receive an energy adder. If the IDR has the lower rate, a subtractor would be applied to the QF's energy price.

If offsets are required at a ratio greater than one-to-one, then the IDR could potentially cause a net reduction in system emissions. In this case, the QF would receive a subtractor, unless it purchased enough offsets to have the same impact on system emissions.

8. *CEERT*

Under CEERT's proposal, residual emissions are explicitly valued during ICEM analysis, while fuel diversity is ensured through designation of a non-fossil IDR and a separate bidding arena for non-fossil bidders. This eliminates controversy over how to calculate adders in the context of emission offsets. CEERT's approach is interim; it supports development of explicit values for environmental benefits.

CEERT recommends that residual emissions be valued explicitly for all three utilities, and that SCAQMD's BACT requirements be the basis for valuing all residual emissions within the state. According to CEERT, Public Utilities Code § 701.1 requires valuation of residual emissions in electric generation planning.

CEERT recommends that half of all identified need be allocated through the non-fossil bidding arena. Also, the environmental and fuel diversity benefits of projects bidding in the non-fossil arena should be measured against the costs of a non-fossil IDR. Those costs should be time-differentiated according to the value of deliveries at different hours and seasons.

CEERT does not oppose adders but urges if they are adopted that they not include any offset effects. Resources offering environmental benefits should receive payments based on the value of avoiding residual emissions, and those benefits should affect the ranking of projects in the resource acquisition process.

9. *GRA/IEP*

Half of all identified need should be reserved for non-fossil QFs. The utilities should submit a non-fossil IDR cost estimate with their resource plans. Failing that, the non-fossil IDR could be proxied by the costs of the last non-fossil plant built or approved for construction by the utility.

The utilities should be ordered to cooperate in the development of values for adders. GRA/IEP's proposal is amenable to the incorporation of adders. Detrimental air emissions can be reflected in both adders and emissions values in ICEM.

E. *Environmental Considerations (Starting with Air Quality) and the Value of Fuel Diversity Should Affect Both Planning and Acquisition of New Electric Resources*

[7, 8] Electric resources formerly were valued solely in terms of their energy output and capacity (contribution to system reliability). Such traditional valuation neglects some aspects of the social infrastructure in which electric resources play a vital part. The health and security of our citizens dictate that we now include these aspects.

Air quality (and the lack of it) has measurable impacts on our productivity at work, our enjoyment of leisure, and the very length of our life spans. The political will, expressed at the state and national level, is clear. We must address our air quality problems. While electric generation is not the primary source of criteria pollutants, it is a major contributor. Its emissions impose costs on society that should be accounted for. Least cost planning must become *environmental* least cost planning. See Attachment 5 (Public Utilities Code § 701.1).

Least cost planning principles must also assign a value to fuel diversity. Electric generation serving California continues to be fueled primarily by oil, natural gas, and coal. For example, the Energy Commission found that in 1990, 60% of California's dependable capacity was fossil-fired. (See ER-90 at page 3-1.) These fuels are not renewable, so in the long run we expect they will become significantly more costly as proven and more accessible deposits are exhausted. In the short run, oil has been subject to extreme price spikes and supply disruptions. Natural gas, which can be substituted for oil in many cases, may be subject to similar price risks. The price and supply of coal appear steady, but coal has high environmental costs at every stage of the fuel cycle, from mining and transportation to combustion.[15] The United States has huge domestic coal deposits, but the environmental costs of coal, which are still being assessed, may mean that it is neither so secure nor so cheap a fuel as was once thought.

A resource plan is a "least cost" plan if (among other things) it results in reasonable costs under the most likely future case *and* does not result in unduly high costs under alternative cases with a significant likelihood of occurrence. Fossil fuels are currently cheap and plentiful, but there are short- and long-term risks in assuming that they will continue to be so. A truly least cost electric resource procurement strategy would hedge against these risks by diversifying our generation mix. Developing resources that rely on alternative and renewable fuels will (1) cushion the impact of price shocks in fossil fuel markets, (2) help to avoid such shocks by lowering demand and extending current supplies of fossil fuels, and (3) improve the efficiency and cost-competitiveness of non-fossil technologies.

Having addressed these threshold matters, we turn now to the questions with which we began our summary of parties' positions in the preceding section.

1. *Accounting for Environmental Quality and Fuel Diversity Requires Both Assigning Monetary Values and Making Policy Judgments*

Non-price factors can have measurable economic impacts. To determine just and reasonable rates, this Commission must know how resource procurement decisions will affect rates. The policy instruments by which we are fostering competition in electric generation — namely, the standard offer and avoided cost — are grounded in economics and are used to structure a contractual relationship. For all of these reasons, assigning monetary values seems the best way to begin analyzing how environmental quality and fuel diversity should figure in the planning and acquisition of electric resources.

We will review the results of that analysis in the next BRPU phase, when PG&E, SDG&E, and Edison file resource plans responding to ER-90. At that time, we will consider the recommendations of the utilities and other parties from a policy perspective. We agree with the CEC that quantitative analysis is not (and may never be) so finely developed that its results can be applied mechanically. In particular, we want to wind up with final Standard Offer 4 solicitations that, despite some differences in formulation from ER-90, substantially conform to the ER-90 integrated assessment of need.

The differences we just alluded to stem from our preference for using a fuel diversity premium instead of set-asides in acquiring non-fossil generation. Such a premium enables a better accounting for the benefits and costs of non-fossil generation than do set-asides.[16] Although the ICEM analysis performed in ER-90 did not find any non-fossil IDRs, our treatment of residual emissions places higher values on avoiding such emissions, and we will also impute fuel diversity value to non-fossil QFs where no non-fossil IDRs show up in the respective utility resource plans.

This process (using a fuel diversity premium instead of set-asides) differs from ER-90's, but the purpose is identical and the result should be substantially the same, namely, filling the generation portion of need with a well-diversified portfolio of fossil and non-fossil resources. We propose to do that through a strategy that recognizes the diversity value of non-fossil QFs even where the resource plan using the ER-90 base case contains only fossil IDRs.

We prefer to derive our values for residual emissions from the air management districts' calculations when they set abatement requirements for the various pollutants. The districts are responsible for developing programs to meet our air quality goals, and the districts are best situated to determine values for the costs and benefits of those programs. Where a utility's service area overlaps several air basins, values for residual emissions should come from the most significant air management district for that service area.[17]

Unfortunately, only SCAQMD among the relevant districts has taken final action from which we can derive values. SCAQMD's recommended values for residual emissions are set forth in its BRPU testimony (Exhibit 230). Those values shall be used by Edison in performing ICEM analysis and shall be applied in calculating adders (subtractors) for auction winners. The adder (subtractor) is an adjustment to the QF's energy payment and is separately computed for each pollutant by comparing the QF's and IDR's emission rates.

We also direct the same use of SCAQMD values for SDG&E. The San Diego APCD has proposed rules similar to SCAQMD's or even stricter. Where vigorous regulatory action seems imminent, the extremely low "starting point" values in the Pace University Study are unrealistic. Pending final action by the San Diego APCD, the SCAQMD values are the best available for San Diego.[18]

The situation for PG&E is different because the relevant air management district has not taken steps from which values are clearly deducible. ER-90, however, projects $13 per kilowatt (1987 dollars) as the cost to PG&E of retrofitting its plants for NOx control. (*Id.*, pages 5-7, 5-8.) PG&E's compliance report in the next Update phase should convert this cost to a dollars per ton figure, and provide a supporting explanation of how PG&E calculated the conversion. Alternatively, PG&E may value NOx emissions at 29% of the SCAQMD value. This percentage is determined by comparing the CEC's projections of NOx retrofitting costs for PG&E ($13 per kilowatt) with those for Edison ($45 per kilowatt). Values for most other residual emissions should come from the Pace University Study. The latter study does not contain a value for ROG, so for that pollutant PG&E should use the ER-90 in-state value ($3,300 per ton in 1987 dollars). All of these values, like those for SDG&E and Edison, shall be used by PG&E in performing ICEM analysis and shall be applied in calculating adders (subtractors) for auction winners.

The values adopted today for residual emissions on the PG&E and SDG&E systems are interim values. They should be revised in subsequent Updates to reflect emerging abatement requirements of the relevant air management districts.[19]

Carbon dioxide, a "greenhouse" gas, is not a criteria pollutant, but concern for potential global warming seems certain to result in legislation to control greenhouse gas emissions. Thus, an interim value for carbon emissions (including carbon dioxide) is also prudent. All these utilities should apply the value adopted in ER-90 ($26/ton in 1987 dollars) for carbon emissions.[20] This value will be used in the same ways as the values for criteria pollutants.

2. *Accounting for Environmental Quality and Fuel Diversity Should Affect Both Planning and Acquisition Portions of the Resource Procurement Process*

Once we have determined that clean generation and fuel diversity are valuable things for a utility system, then they must figure both in planning and acquisition as surely as do the system's needs for energy and capacity. This coordination is necessary in order to know how much to pay and how much of a good thing is enough.

Whatever one proposes to acquire, it seems logical to budget before shopping and to expect to pay for what one wants. Stated bluntly, society cannot reasonably expect to get the clean air that society values without offering to pay for it. In fact, offering to pay will stimulate the competition that should ultimately drive down the cost of clean air.

3. *The Same Value for Residual Emissions Should Apply to All Resources Serving a Particular Utility*

[9] The environmental costs of electricity generated from sources outside California or outside the service area of the utility acquiring that electricity should be calculated the same as if the electricity were generated within the utility's service area.

Our decision to base valuation on the system served, rather than the site of the power plant, relies on long-standing principles of utility regulation. The ratepayers served by an interconnected utility system all bear the costs of that system. Edison customers in the Los Angeles air basin already bear the costs and get the benefits of Edison's participation in out-of-state coal and nuclear power plants, as do customers closer to those plants. When we establish revenue requirements and design rates, we do so on the basis of total utility system, not on the basis of location either of facilities or communities.

The counter-arguments are that Californians should not have to pay for cleaning up neighboring states and that the values assigned to the abatement of residual emissions come from air quality regulators with jurisdiction over the proposed power plant, not necessarily from local air quality regulators in the service area of the acquiring utility. We are not persuaded.

First, regarding the source of air quality values, these should reflect the utilities' marginal costs of emission control. An appropriate measure for such marginal costs is the cost of abatement actions required in those air basins where the utilities face major costs of compliance with air quality standards. This is precisely the derivation of the values we have directed the utilities to use.

Second, referring to the argument about cleaning up other states, that argument misses the real geographical issue we are facing. Our choice actually is between promoting dirty generation out of state and promoting clean generation wherever it is located. As noted earlier, the "value" of residual emissions is negative. Such valuation in effect increases the price of any project with such emissions. If we value emissions for in-state projects but not for out-of-state projects, we confer an enormous competitive advantage on the latter for no reason other than that they foul someone else's air. But a policy of "exporting" pollution would not work if other states were to adopt a similar policy, and it would not work in any case because pollution, once emitted, does not respect state lines.

The most important point, however, goes back to our earlier statement regarding interconnected utility systems. If more clean generation is added to such a system, the utility can reduce its reliance on its dirtier plants. Edison, by buying power from a geothermal or solar QF (to name two examples), can help clean up the air in Los Angeles whether the QF is in or out of state, on or off system. Air quality adders (or subtractors, as appropriate) should therefore apply uniformly to energy payments to any final Standard Offer 4 QF, regardless of its location.

4. *Non-fossil QFs Should Be Paid a Premium If Non-fossil IDRs Depend on Imputed Fuel Diversity Value*

[10] The CEC in ER-90 did not adopt a method for quantifying the value of fuel diversity, although the CEC continues to support development of non-fossil and renewable resources. This created a quandary for the CEC when its ICEM analysis failed to identify any non-fossil deferrable resources even with the inclusion of the social costs of air emissions. The effect of such inclusion was rather to accelerate the need for new gas-fired resources to replace aging gas-fired units now on the utility systems.[21]

In order to capture the value of fuel diversity and to promote continued advances in non-fossil and renewable generation technologies, the CEC determined that a portion of needed MW for SDG&E and Edison should be set aside for potential deferral by non-fossil bidders. The CEC also determined that PG&E's system is already diverse and accordingly did not recommend any set-aside in the PG&E auction.

We agree with the policy basis of the CEC's set-aside recommendation. We will implement that policy in a different way, however. Our implementation will enable us to check the potential ratepayer impact of the environmental least cost resource plan (possibly including a fuel diversity premium) against the ratepayer impact of traditional least cost planning that looks only at the capital and running costs of candidate IDRs.

The problem with set-asides is that they mask the cost of the policy they are supposed to serve. Without quantifying the value of fuel diversity, we cannot tell whether a 50% set-aside is too much or too little. PG&E's price cap is little, if any, improvement, since the cap is meaningless if we can acquire non-fossil resources more cheaply and counter-productive if the value of such resources is greater than the cap.[22] We can confidently predict, however, that a set-aside will increase the cost to ratepayers of acquiring such resources by creating a separate bidding arena for non-fossil resources.

The approach we adopt in today's decision tells us exactly how much value we need to get from non-fossil IDRs, in the form of reduced air emissions and (if necessary) fuel price volatility "insurance," in order to prefer them to other candidate IDRs. The approach also ensures that the auction yields maximum benefits to ratepayers by allowing all technologies to participate.

Under our approach, each utility will perform ICEM analysis using values for residual emissions as specified in Section IV.E.1 above. In our interim approach, if a non-fossil IDR appears in the "deferral window" (through 1999), a fuel diversity premium will not be calculated.[23] If a non-fossil IDR does not appear, the utility will calculate a value for fuel diversity sufficient to have a non-fossil candidate resource appear as the earliest IDR in the deferral window.

To calculate the fuel diversity premium, the utility will perform an additional ICEM run, replacing the first fossil IDR (as identified in the utility's fully built-out base case resource plan) with the most cost-effective non-fossil candidate resource. No other changes would be made to the base case resource plan.

The increase in total system operating and capital costs resulting from the replacement of the fossil IDR with the non-fossil candidate will then be derived in net present value terms, and will represent the cost which ratepayers would incur to acquire a non-fossil resource. This cost will be divided by the capacity of the non-fossil candidate, and then annualized using the same discount and inflation rates otherwise used to convert one-time capital costs into cost streams.

The annualized fuel diversity premium, expressed in dollars per kilowatt, will be applied as an additional capacity payment (based on effective capacity) to non-fossil and renewable QFs, and will be published before the auction. These QFs can then factor in this premium in formulating their bids. A QF that does not provide "fuel diversity" as defined in Section IV.B above would not be eligible to receive the premium.

Non-fossil QFs will have a substantial, value-based advantage in any auction using a fuel diversity premium. All other QFs face major costs due to offsets and will not receive the fuel diversity premium. Thus, we expect that non-fossil QFs can fill a substantial portion of the need offered through an auction using a fuel diversity premium.

We are not at this point absolutely committed to using the premium derived by this approach in the coming auction. The final decision on this point will be made in the next phase of the BRPU. At that time, we will carefully examine the potential ratepayer impacts together with relevant uncertainties, strategic preferences, and policies both of this Commission and the CEC. In particular, we want to explore the benefits of non-fossil resources under a high fossil fuel cost scenario using our adopted values for residual emissions, since this is the contingency that a diversity strategy is intended to address.

We have two further observations regarding fuel diversity value. First, our approach today is strictly interim. Investment theory has reached a point where the value of diversification ought to be calculable, and it ought to be incorporated into any kind of least cost resource planning, whether from the traditional or social perspective. We look to the CEC for continued work on fuel diversity value in the next ER/BRPU cycle.

Second, we agree with the CEC that only a modest fuel diversity premium should be adequate for our purposes. (See ER-90 at page 4-9; cf. pages 6-12, 6-13.) We note that some non-fossil QFs are successfully proceeding with Standard Offer 2 contracts. Although the capacity and energy payments under final Standard Offer 4 should be lower than under Standard Offer 2, the environmental adders payable to QFs with low air emissions would probably make final Standard Offer 4 the more attractive contract for such QFs, and we expect that non-fossil QFs could therefore compete successfully in bidding to defer any type of IDR. For the same reason, we are surprised that the CEC's recognition of air emission values did not produce non-fossil IDRs by 1999 in its ICEM analysis.

Conceivably, the capital costs used for such IDRs were too high. QFs may be reluctant, for competitive reasons, to reveal detailed cost data. The utilities, on the other hand, have minimal experience with building non-fossil generation.[24]

The capital cost of non-fossil and renewable technologies is often proprietary information but public sources may exist, including published bids submitted for generation resource solicitations conducted here and in other states. We invite all parties to critically review utility resource plans filed for the next phase, with special attention to the capital cost data for non-fossil IDRs.

5. *Impact of Offsets Should Be Reflected in the Resource Procurement Process*

[11] Builders of many types of power plants in many sites for those plants will have to acquire air emissions offsets. This fact, like residual emissions themselves, must be reflected in both resource planning and acquisition.

Some parties would disregard offsets, at least for purposes of resource acquisition. These parties fear potential results that seem to them perverse. For example, a gas-fired cogenerator that had to acquire offsets in a ratio of 1.2 to 1 might thereby qualify for an air quality adder when competing against a non-fossil IDR with zero emissions of criteria pollutants. That the acquisition process "reads" the cogenerator as cleaner than a geothermal IDR strikes some parties as outrageous.

We disagree. A cogenerator that cleans up 120% of its emissions *is* cleaner, from a social perspective, than a geothermal plant with zero emissions. The desirability of taking a social perspective on environmental quality is precisely the reason for considering residual emissions in the resource procurement process. We don't know whether a cogenerator could bear these offset costs and still bid successfully against non-fossil QFs to defer the geothermal plant; but if the cogenerator is successful, society will have cleaner air at a competitive price.[25]

On the other hand, the offset markets are new, and until all parties have more experience, it seems prudent to limit the extent to which they influence our procurement process. We will only consider those offsets acquired by a QF (1) to comply with requirements of the air management district with jurisdiction over the QF's powerplant, or (2) to avoid a subtractor relative to the IDR. Any offset for the latter purposes would have to be located within the district and subject to the jurisdiction of the air quality regulator that would have set the environmental requirements for the IDR.

We understand that air management districts may be considering refinements or alternatives to their offset rules. As with the value of residual emissions, we intend to work closely with the districts and to ensure that the development of new generation will meet our goals of clean air and workable competition.

6. *Further Thoughts on Clean Air and Energy Policy Tradeoffs*

Today's decision is a compromise that reasonably reflects the tradeoffs society must make in everyday economic choices. At one extreme, environmentalists who oppose all resources that increase net emissions will not be satisfied. Our procurement process considers clean air along with other benefits, and a bidder's other benefits may outweigh its residual emissions in some circumstances where competing bidders have lower emissions. We want clean air, but we are limiting the price we are willing to pay for it.

At the other extreme, some commenters have argued that the decision over-values clean air by applying the same emissions values to each resource serving a particular utility, even if the resource is located in an area that meets clean air standards. By implication, clean air in such a location is less valuable (or increments of pollution are less costly) than in non-attainment areas such as the Los Angeles basin. The result according to these commenters is that the utilities may buy less electricity than would be desirable, from an economic standpoint, from resources outside the key non-attainment air basins (the Los Angeles, San Diego, and San Francisco Bay areas) that concern us here.

There are at least two major problems with this argument. First, the externalities we are dealing with are those occurring at the point of consumption, not at the point of production. This is the basis of our adopted valuation method.

Second, even assuming that regional economic transactions balancing energy and air quality might be desirable, much work needs to be done before a market for such transactions could work properly. There is always a cost imposed by an increment of air pollution, though that cost may not be identical in all jurisdictions.[26] However, the vast majority of the relevant jurisdictions in the West have not yet followed SCAQMD in establishing values for the various air pollutants.

Even when all the jurisdictions have spoken, our adopted valuation method may still be appropriate as representing the utilities' marginal costs of control. Nevertheless, clean air policy is evolving rapidly, and we will revisit the subject of emissions valuation when the regional air quality situation becomes more definite. It will also be time for a fundamental change when we arrive at a truly competitive market in electricity, when regulatory determination and enforcement of avoided cost is no longer necessary. However, we will continue to refine our values for residual emissions as actions of the California air quality regulators enable us to quantify more precisely the avoided environmental costs for our regulated electric utilities.

Also, we note that early this year, in Docket No. 89-752 of the Nevada Public Service Commission, that Commission adopted values for residual air emissions. This provides an opportunity for the respondents to perform an alternative resource plan scenario that should illuminate the impact of residual emissions valuation on the choice and costs of potential IDRs. In the alternative scenario, the valuation would depend on whether or not the residual emissions associated with the candidate new plant or power purchase would occur in an area that meets AAQS. If the area is a nonattainment area, then the utility would apply the emissions values that we adopt in today's decision. If the area is an attainment area, then the utility would apply the Nevada Commission's values. (Essentially, these values would be representative of pollution costs in a jurisdiction with generally good air quality.) We direct the respondents to include such an alternative scenario in their compliance filings following today's decision.

We emphasize that our adopted approach will *not* discourage energy imports per se relative to the status quo. Both our adopted approach and the status quo value residual emissions uniformly, but the status quo assigns no cost to them at all, with the result that dirtier forms of generation, regardless of their location, appear more cost-effective than they really are. Today's decision will result in an environmental least cost plan that takes advantage of clean resources wherever they are located.

However, bidders and IDRs in attainment areas will continue to have a significant cost advantage compared to competing projects in, e.g., Los Angeles or San Diego, because the latter will have to internalize high costs of compliance with local air quality regulations, such as offset requirements greater than 1:1. Thus, we anticipate that today's decision will have little effect on the significant role that imported electricity plays in California's energy strategy.

7. *Emissions Monitoring*

Our adders system requires means to ensure that the QF's actual emissions are consistent with its claimed emissions. Several factors (e.g., the QF's size and technology, and the requirements of the air quality regulator in whose jurisdiction the QF is located) may affect the type of monitoring that is appropriate.

We do not have a record that allows us to resolve these issues at this time. We invite parties to address them in the next phase of the Update. We especially solicit input from air quality regulators on the type(s) of emissions monitoring that would be required for power plants subject to their jurisdiction.

V. *Competition Between Fossil and Non-fossil QFs*

[12] Final Standard Offer 4 now has no front-loading whatsoever in its pricing provisions and a basic contract term (defined as "Period 2") of 15 years.[27] Also, the structure of fixed and variable payments under final Standard Offer 4 differs according to whether or not the QF is oil/gas-fired. Most of the parties have testified that these provisions place capital-intensive QFs (which are generally those that use alternative or renewable fuels) at a competitive disadvantage relative to oil/gas-fired QFs. They recommend greater flexibility, which they believe can be achieved without sacrificing avoided cost principles. We agree and are adopting certain changes, as described below.

A. *Length of Final Standard Offer 4 Contracts*

When we decided to set the length of Period 2, we heard a large number of proposed approaches. Some parties called for maximum terms for final Standard Offer 4 contracts, some for minimum and maximum terms. Some parties wanted a term stated in years (proposals ranged from 10 to 30), or as the projected useful

life of the IDR, or some variation on these approaches. We chose not to have a minimum or maximum term but instead set Period 2 at 15 years for *all* final Standard Offer 4 contracts. We chose 15 years in order to lessen ratepayer exposure to planning error. (See D.86-07-004, 21 CPUC 2d 340, 375, 76 PUR4th 1 [1986].) Some further discussion of our assumptions and information at the time of our prior decision will help explain why we are now changing that decision.

In 1978, Congress enacted five related bills, including PURPA, that broadly addressed the nation's energy problems. From that time through the late 1980s, most observers believed that major new utility generation facilities were likely to be coal-fired. The abundance of domestic coal deposits made that fuel a linchpin of national energy policy around the time of the second oil embargo. This Commission and the CEC were reviewing huge coal plants proposed by California utilities; most of these projects were eventually abandoned, but many coal plants were built in the Northwest and the Inland Southwest, in some cases with equity participation by California municipal or investor-owned utilities.

Coal plants have low fuel costs but high capital requirements. The QF program was instituted, in part, to relieve ratepayers of the risks involved in such capital-intensive utility construction projects. When such a project is avoided by QFs, the QF developers assume all the risks of construction cost overruns and delays. Furthermore, a long-run standard offer based on a coal plant would solve most financing problems for QFs because fixed costs of the avoided coal plant would make up most of the QFs' payment stream.

That sounded good, but we saw the 15-year contract term as an additional way to cut ratepayer risks. Forecasts can be high or low, utility systems change over time, so why not offer QFs a substantial period of price certainty but not necessarily the whole life of the IDR? If the QF wanted to continue on a long-run contract after Period 2, it could still do so, provided that it was a successful bidder in an auction to avoid a plant scheduled to come on-line at the end of its 15-year term. In this way, we hoped to ensure that the utilities' long-run QF contracts conformed as closely as possible to current perceptions of their long-run needs. Moreover, the ratepayer would actually be better off than if the utility had built the IDR, which would have to be paid for fully even though the utility's needs had changed from those we had anticipated in approving the IDR.

The problem with the above reasoning is that some QFs are also capital-intensive and require longer terms than 15 years. Geothermal, solar, and other QFs using alternative or renewable fuels are some of the most desirable QFs from the standpoint of environmental quality and fuel diversity, but in general their ratio of fixed-to-variable costs is more like that of a coal plant than that of an oil/gas-fired cogenerator. An inflexible 15-year term treats this difference as immaterial.

The materiality of this difference, however, has become clear in light of the findings of ER-90. The CEC did considerable ICEM analysis and found that the likely IDRs for PG&E, SDG&E, and Edison are not coal-fired, but gas-fired (new combined cycle plants or repowering of existing gas units). Gas-fired plants are likely to be far less capital-intensive than coal plants. This compounds the impact of a relatively short contract term on capital-intensive QFs. The contract term provides less certainty than they would like and, depending on the IDR, the fixed costs paid out over that term may be much lower than we anticipated in approving the 15-year term.

We have concluded that the prescribed 15 year term is not likely to be a good deal for ratepayers. Risk reduction is one of the important goals of the QF program, but part of the risk reduction comes from the diversity that QFs bring to our resource mix. Diversity is jeopardized by a limitation on contract length that puts non-fossil and renewable QFs at a disadvantage.

Instead, the term of Period 2 should be up to the full projected life of the IDR.[28] This term will be available to all QFs, irrespective of their technology. This approach will help to level the playing field for all QFs and will expose ratepayers to risks no greater (and probably less) than what they would face if the utility were to build the IDR. There will also be a minimum term of 15 years (where the projected life of the IDR is at least that long) or the projected life of the IDR if it is less than 15 years.

We stress that we are not precluding short-lived IDRs, even ones lasting less than 15 years. The utility may be considering 10-15 year plant life extensions that involve energy-related capital costs or power purchases of such length with a high level of fixed costs. There may be QFs interested in deferring IDRs with such shorter lives, and we want to explore this, at least until experience demonstrates a low-end threshold for Period 2.

B. *Levelization of Shortage Costs*

Final Standard Offer 4 uses a payout method called "ramping." The method applies to the fixed costs of an IDR and ensures that in Period 2 the QF gets paid exactly those annualized fixed costs net of inflation.[29]

Capital-intensive QFs prefer that contracts permit some degree of "front-loading," meaning that the value of payments under the contract declines over time. The concern, as with contract length, is financing. QFs face higher debt service in the early years of their operations and would like a corresponding revenue stream.

In the past, we have allowed some front-loading in QF payments. The most common form is levelization of so-called shortage costs.[30] A levelized payment is constant in nominal dollars and thus is declining in "real" dollars (that is, net of inflation). Both Standard Offer 2 and interim Standard Offer 4 have levelized shortage costs, together with security provisions that ensure the QF returns overpayments if it ceases operation before the end of the contract.

We have concluded that levelized shortage costs together with appropriate security provisions are reasonable for final Standard Offer 4. We will allow a final Standard Offer 4 QF to choose either a ramped payment stream or a partially levelized payment stream.

There are three reasons for making this change. First, as the QFs correctly note, levelization represents far less front-loading than we allow utilities in their recovery of capital investments. Second, as we discussed in the foregoing section, the CEC's latest findings on potential IDRs suggest that the difficulty in financing capital-intensive QFs will be greater than we anticipated when we chose to totally exclude front-loading from final Standard Offer 4. Third, levelization will increase the QF's cash flow without improperly shifting risk to ratepayers, who will be able to recover any excess payments should the QF fail.

Levelization will be available to all QFs, irrespective of their technology. This is consistent with other changes in today's decision designed to achieve as far as possible uniform treatment of all QFs.

We do not permit levelization of any costs other than shortage costs, nor do we permit levelization without appropriate security.[31] Such front-loading would impose unacceptable risks on ratepayers, and QFs have not demonstrated that their financing requires levelization of anything besides shortage costs. (Indeed, our experience with Standard Offer 2 indicates otherwise.) Moreover, in Section V.C below, we make certain changes in our auction format that will effectively tailor the payment stream for each winning bidder to correspond to its own cost structure. This should substantially mitigate the financing problems of capital-intensive QFs.

C. *Energy Bidding and QF Payment Structure*

[13] In D.86-07-004 (21 CPUC 2d 340, 76 PUR4th 1 [1986]), we recognized that ratepayers and QFs would both be at high risk if the payment structure for capacity and energy in QF contracts was wholly insensitive to the QFs' fixed and variable cost structure. This concern led us to adopt the incremental energy rate (IER) payment option for oil/gas-fired cogenerators.[32]

In Phase 1B, many parties, including the CEC, PG&E, Edison, and DRA, have recommended that we drop this option in favor of a new approach to payment structure. They argue that the IER option places solar, geothermal, and other capital-intensive QFs at a competitive disadvantage relative to oil/gas-fired cogenerators because there is no similar mechanism to link the capital-intensive QF's cost stream with its payment structure. Also, DRA argues that the IER option exposes ratepayers to more fuel price risk than is necessary to reflect unexpected changes to a cogenerator's energy costs.

Instead, these parties, along with CEERT, propose that all QFs bid capacity and energy prices separately. We agree that such bidding will allow fossil and non-fossil QFs equal opportunity to provide their full fuel diversity and efficiency benefits to ratepayers.

1. *Background*

a. *Power Plant Cost Structure and Payments to QFs*

All power plants have costs that are characterized as either fixed or variable. Fixed costs mostly reflect the capital invested in building the plant; variable costs reflect expenditures to run the plant, chiefly fuel. Our decisions use the terms "variable costs" and "energy costs" interchangeably.

Different power plants have different cost streams. Some have high fixed and low variable costs, while others have low fixed and high variable costs. The latter category includes plants that chiefly rely on oil or gas; all other plants fall into the former category.

The issue here is not the total amount to be paid QFs under final Standard Offer 4 but rather how that amount is to be split up for purposes of QF payments. Specifically, should QF payments for capacity and energy match the IDR's mix of fixed and variable costs, or should the IDR costs be redistributed to match the QF's own mix? The answer to that question now depends on the QF's fuel type.

b. *Origin of the IER Option*

The IER option was conceived at a time when, as discussed earlier in this decision, the California utilities were proposing to build large, central station coal plants. Coal plants have low, stable fuel costs but high capital costs. We expected that capital-intensive QFs could compete with a coal plant since their pattern of fixed and variable costs would match that of the expected coal-fired IDRs.

We believed, however, that cogenerators would not be able to compete to defer these resources if their energy payments were derived from the low energy costs of such IDRs. If cogenerators did try to compete on such a basis, we feared that ratepayers would be exposed to grave default risks. The IER option responded to this problem.

The IER option was designed to convert payments based on IDRs with high fixed and low variable costs to a payment structure suitable for cogenerator QFs, who have low fixed and high variable costs.[33] We intended the IER option to reflect the cogenerator's proportion of energy costs in its payment structure but not to increase projected total payments (capacity plus energy) over the life of the contract.

The IER option relieves cogenerators from the need to emulate the IDR's cost structure. But for capital-intensive QFs, payments under final Standard Offer 4 are now designed to emulate the IDR's cost structure.

2. *The IER Option Is Not a Complete Solution to the Payment Structure Problem and Creates Unequal Competition*

When we adopted the IER option, we stressed our intention to monitor its impact on the utility system. We indicated that we would reconsider its merits in future Updates. Our chief concern was that the IER option might perpetuate California's over-dependence on oil/gas-fired generation, thus exposing ratepayers to excessive fuel price volatility risk.

In Phase IB, nearly all parties agree that the IER option does not go far enough to address the problems which arise when a QF's payments are insensitive to its fixed and variable cost pattern. They identify two deficiencies in the current payment structure that deprive ratepayers of the full fuel diversity and efficiency benefits offered by QFs. First, the current auction protocol and payment structure has no provisions to relieve capital-intensive QFs of the need to emulate the IDR's cost structure.

Second, payments to cogenerators under the IER option may transfer too much risk to ratepayers.

a. *Financial Emulation*

The current auction requires all QFs to bid a capacity price expressed as a percentage of the capital costs of the IDR. For non-fossil QFs, all other costs are recovered through variable payments equal to the variable costs of the IDR. This puts capital-intensive QFs at a disadvantage, relative to oil/gas-fired QFs, when bidding on an IDR, such as a combined cycle, with a low fixed and high variable cost structure.

The disadvantage occurs because a capital-intensive QF would have to recover a portion of its fixed costs through IDR-based variable payments. Its cost coverage is uncertain, so its financing costs will be high. Capital-intensive QFs must finance a large proportion of total costs, so these extra costs may have a significant effect on their ability to compete in the auction. If an otherwise competitive non-fossil QF is precluded from winning the bid, ratepayers will lose significant fuel diversity and environmental benefits.

Current circumstances dictate that we address the financial emulation problem. Despite some progress, California utilities remain highly dependent on oil/gas-fired resources. In ER-90, the CEC found that in 1990, one-half of California's dependable capacity was gas-fired. Further, the CEC's ICEM analysis found that likely IDRs for all the investor-owned utilities are gas-fired combined cycles or repowered existing gas units. We are thus in a situation where we need fuel diversity but are unlikely, without modifying final Standard Offer 4, to acquire the QFs that could help diversify our fuel mix.

b. *Ratepayer Risk*

DRA believes that the IER option exposes ratepayers to unnecessary fuel price risk because it links the IDR's energy costs and some of the cogenerator's capacity payments to oil and gas prices. According to DRA, the IDR's energy and capital costs have only limited relation to the fuel price risks associated with the *cogenerator's* energy costs.

To mitigate the contract default risk which arises from the financial emulation problem, DRA would link only the cogenerator's energy costs to fluctuating oil and gas prices. DRA would allow cogenerators to bid on IDRs that are not oil/gas-fired, but in that case DRA would impute an added 10% to the cogenerator's energy price bid. DRA believes that this imputation is necessary to ensure that ratepayers are getting a good deal whenever a cogenerator defers a non-fossil IDR.

We share DRA's concern about ratepayer risk under the IER option. We do not adopt DRA's proposed imputation because ratepayers are adequately shielded by our payment structure modifications (below) and the approach to fuel diversity described in Section IV of today's decision.

3. *Solution: Bid Both Energy and Capacity*

Both deficiencies in the current payment structure are corrected if QFs are required to bid both energy and capacity prices. Energy payments would then be escalated to reflect the actual fuel costs of the winning bidders. Most parties, including the CEC, CEERT, DRA, PG&E, and Edison, support these modifications.

We are persuaded that the IDR should remain the benchmark for QF bidding but that avoided cost principles do not require QFs to match the IDR payment structure. Both capital-intensive QFs and cogenerators should benefit from bidding a payment structure that corresponds to the cost structure of the plant to be financed. This translates to lower risks to QFs, and ultimately to ratepayers. Indeed, we are more likely to achieve our goals of fair competition and a diverse portfolio of QFs if QFs are not constrained to an IDR- or IER-based payment structure.

Bidding energy and capacity has many advantages. First, it permits all types of QFs to bid a payment structure appropriate to their technology. The current bidding system favors QFs whose cost structure is similar to that of the

IDR. The extra financing cost for QFs whose cost structure differs from the IDR means that they must bid a higher price than they could under a more appropriate payment structure. Bidding both energy and capacity allows all QFs the same opportunity to have their benefits to the ratepayer fairly evaluated.

Second, such bidding shields ratepayers from undue fuel price risks. By escalating energy payments based on the QF's own fuel type, ratepayers get the fuel diversity benefits of non-fossil QFs and the fuel efficiency benefits of cogenerators.

Third, having a more accurate picture of the QF's energy cost means that utilities can dispatch the system more efficiently. Economic curtailment decisions are based on the variable cost payments made to QFs. Currently, variable cost payments are based on the projected costs of the IDR. Changing this to link payments to a QF's own cost stream should enable the purchasing utility to make more efficient curtailment decisions and should make QFs indifferent to such decisions. In particular, those QFs (e.g., solar) whose fuel source makes it hard for them to curtail should benefit since their low variable costs will virtually eliminate the possibility of economic curtailment.

4. *Implementation*

DRA, PG&E, and Edison all provided detailed methods to implement a system which requires bidding of energy and capacity. The methods do not differ drastically; however, each was developed as part of an integrated proposal in Phase 1B. In light of the rest of today's decision, parties may want to reconsider some aspects of their implementation proposals. Parties are directed to work out the details of implementation and the necessary contract changes in a workshop. As guidance to the parties, we describe below our general expectations of energy and capacity bidding under a second-price auction with environmental adders.

In the following description, we modify the proposed decision in one respect regarding bid preparation and evaluation. The proposed decision would compare the projected net present value of the IDR with that offered by the competing bids. This comparison seems unduly complex and requires assumptions about the respective bidders' energy delivery profiles. On further consideration, we prefer a first-year cost basis for evaluation. Such evaluation involves combining the fixed and variable costs of the IDR into a single cents per kilowatt hour figure, and similarly combining the energy and capacity bids of each bidder. Where the IDR and bid project have different escalation rates, these can be converted to a common basis using the methodology illustrated in DRA's testimony. (See Exhibit 223 and Appendix A to DRA's concurrent brief.)

Before the auction, the utility will publish all pertinent physical and cost characteristics of the IDR. These include economic life, capacity factor and hours of operation, shortage and other capital costs (and allocation factors for those costs), fuel type(s), residual emission rates, offsets, operation and maintenance costs, first year fuel price, heat rate, assumed fuel price escalator, GNP deflator, and all other projections or assumptions specific to the IDR used in calculating its cost-effectiveness. Using these characteristics and an explicit methodology, the utility will combine the stream of projected fixed and variable costs into a single first-year cost expressed in cents per kilowatt hour. This number will be the IDR benchmark.

QFs will then analyze their own cost characteristics compared to the IDR. They will submit a sealed bid for a stated effective capacity and separately stated variable (energy) and fixed (capacity) prices, with the following knowledge. First, they will know that the utility will recombine their energy and capacity price into a single cents per kilowatt hour first-year cost, using the same methodology used to calculate the IDR benchmark. Second, they will know that the winning bidders will be chosen under second-price rules by comparing each bidder's and the IDR's projected first-year cost. Finally, they will know what environmental adders/subtractors (and fuel diversity premium, if any) they can expect to receive if they win the bid.

Once the winning bidders are chosen, variable payments will be based on the actual energy price bid plus any environmental adders/subtractors. Escalation will depend on the fuel type of the QF. Variable payments to non-fossil QFs will escalate with GNP. Variable payments to other QFs will escalate based on the same fuel index and price update schedule already adopted for final Standard Offer 4.

Capacity payments will be determined by subtracting the energy bid by the winning QF (or the converted energy price, where the QF's energy bid was converted to get a common escalation basis) from the *total* first-year cost of the lowest losing bid. The remaining cents per kilowatt hour will be converted to dollars per kilowatt fixed payments, will be divided between shortage and other capital costs, and will be paid, as already adopted, on a time-differentiated basis. QFs can choose to receive levelized shortage payments as described in Section V.B above.

5. *Energy Bidding and Curtailment*

Much of the policy basis for energy bidding is that the utility dispatcher should be making decisions to dispatch or curtail a specific resource based on accurate knowledge of the running costs of all generation resources (including QFs) at the utility's disposal. The policy necessarily implies that low running cost QFs can expect to be curtailed very rarely, while high running cost QFs (basically, oil/gas-fired cogenerators) should plan to be curtailed, or to receive an energy payment based on actual system running costs, for many hours during the year. We must reconsider the curtailment options under final Standard Offer 4 to ensure that the options are consistent with this policy. We are particularly concerned about three current aspects of curtailment.

First, the QF can now choose to be curtailed for a theoretically unlimited number of hours per year but only if the purchasing utility would otherwise experience *negative* avoided costs due to continued deliveries from that QF. We have no record that the respondent utilities have ever experienced such conditions on their systems or requested QFs to curtail for this reason.[34] We question the continued need for this option. Low running cost QFs need not hesitate to choose the economic curtailment option, since the dispatcher will now see their true running costs, and a utility that used its curtailment authority imprudently would be subject to having its excessive energy expenses disallowed. Cogenerators, on the other hand, should be *required* to take economic curtailment; the advantages of energy bidding would largely disappear if the dispatcher were unable to curtail a high running cost unit except under negative avoided cost conditions.

Second, the other curtailment option now available under final Standard Offer 4 allows the utility to curtail for any reason but only up to 1,500 hours per year. Reports filed regularly by the utilities indicate that gas-fired units are on the margin the majority of the time, but that other resources, hours on the margin could easily exceed 1,500 hours per year. This suggests that the 1,500-hour limit is too low. The payment structure of final Standard Offer 4 now assures the QF of coverage of its fixed costs, so we believe that the purchasing utility can and should be vested with more liberal curtailment authority. However, we also believe that "economic" curtailment should continue to allow the QF either to actually curtail to a minimum level, *or* to generate normally but receive a specially calculated energy payment.[35]

Third, the QF choosing the current economic curtailment option would receive energy payments based on the IDR's running costs but time-differentiated according to the system load profile and adjusted to assume curtailment during low cost hours. With energy bidding, the QF would receive energy payments based on its own running costs. We therefore question the need to continue this complex calculation of energy payments during non-curtailment hours. The QF instead should be paid according to its energy bid (for hours when the IDR was planned to run) or the purchasing utility's short-run avoided operating costs (for hours when the IDR was planned not to run).

Comments on the proposed decision generally support the bidding innovations in this section but seek clarification or reassurance on a number of points. First, economic curtailment affects only energy payments to QFs, not their capacity payments. This is already clear in the curtailment provisions of final Standard Offer 4, and this aspect of these provisions is continued under today's decision. Second, the utility dispatcher shall look only to the QF's energy bid in deciding whether to invoke economic curtailment, and shall disregard for these purposes any air quality adder (subtractor) or fixed payments (including the fuel diversity premium, if any) applicable to that QF.

GRA/IEP believe that, for the time being, some overall limitation on curtailability is appropriate. We agree, but we will leave to the workshop the question of how much to raise the current 1500-hour ceiling. GRA/IEP also ask us to provide for monthly audits of the utilities' dispatch logs "so that unwarranted curtailments are discovered and terminated in the shortest possible time." (GRA/IEP comments, page 6.) The audit mechanism proposed by GRA/IEP is unclear, but we agree in principle that increased QF responsiveness to the purchasing utility should be accompanied by increased utility accountability. This subject also appears to be appropriate for the workshop, as there may be various ways to accommodate QF concerns in this regard.

As previously noted, we will hold a workshop shortly after today's decision to develop appropriate revisions to the final Standard Offer 4 contract. We note that the current curtailment provisions were cooperatively developed, and we will allow the parties at the workshop latitude to consider modifications to these provisions; however, the modifications should respond to the concerns we have just expressed.

VI. *The Second-Price Auction*

[14] In Phase 1B we revisited the issue of auction format. The specific issue is what price to pay winning bidders. Earlier, in D.86-07-004, we adopted Edison's proposal that final Standard Offer 4 contracts be awarded to the low-bidding QFs, up to the total capacity of the IDR, but that the price paid to these QFs be that in the lowest *losing* bid. This is referred to as a "second-price" auction, and also as a "uniform price" auction in that it results in a single price for winners in any given round of bidding.

Since D.86-07-004, Edison has joined PG&E and SDG&E in urging that each winning QF be paid the price it bids. This so-called "first-price" auction results in "discriminative" pricing in that sellers (here, winning QFs) are paid different prices for the same product.

This debate takes us back to the fundamentals of avoided cost pricing and competitive markets. We find that the principles supporting our adoption of full avoided cost pricing for QFs (in D.91109) also apply to our choice of auction format. The second-price auction better serves our policies in the QF program and should be retained.

A. *How Competitive Markets Work*

[l] Generally speaking, a competitive market in any given commodity will arrive at a uniform price for that commodity. This uniform price — the "market-clearing" price — is the price where supply and demand are in equilibrium. That equilibrium shows that the resources consumed in producing the last increment of the commodity exactly match the value to society of that increment. In other words, the level of production of the commodity has reached its social optimum.

The market-clearing price is probably well above the marginal costs of many of the sellers in that market. In fact, it is the potential for sales at a price above marginal costs (which the textbooks call "economic rent") that attracts new entrants and promotes technological innovation. The consumer also benefits from economic rents because in the long run, competition will increase and technological innovation will lower production costs. The result is that the market-clearing price drops.

Any rule that tends to constrain each seller to a price at exactly its marginal cost will discourage investment. There will be few new entrants, little innovation, and less production than would have occurred had the market been allowed to "clear." In other words, the total production of the commodity will fall short of the social optimum. The consumer also suffers because the declining market-clearing price expected in a fully competitive market never materializes.

The uniform pricing in a second-price auction conforms much more closely to the market-clearing price of a competitive market than does discriminative pricing in a first-price auction. Our adoption of a first-price auction would reduce competition in the California electric generation market over the long term, which means that over the long term, consumers would suffer. As we will show next, the short-term benefits claimed for the first-price auction are also illusory.

B. *Contracts Should Go to Low-cost Producers, Not Clever Bidders*

Figure A (reproduced from the testimony of PG&E witness Kahn in Exhibit 207, page 49) seems to hypnotize advocates of the first-price auction.

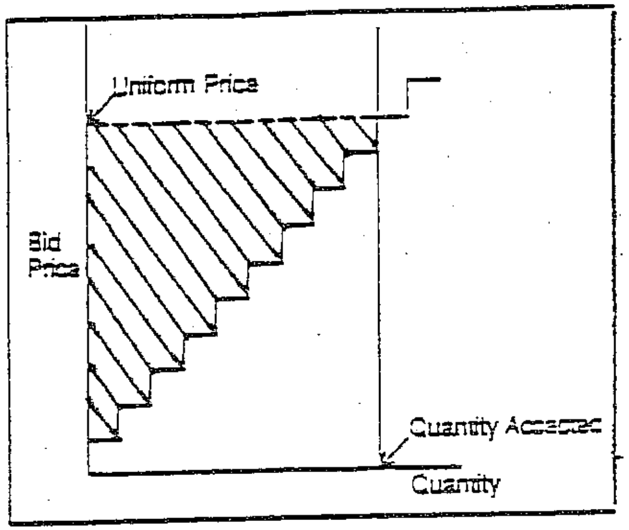

Figure A.

Each "step" in the figure represents a block of capacity bid at a particular price. The "Quantity Accepted" for purposes of this discussion represents the capacity of the IDR. The "Uniform Price" is the price bid by the lowest loser (i.e., the first block of capacity to the right of the Quantity Accepted). Advocates of discriminative pricing insist that the dollars represented by the shaded area in the figure (between the Uniform Price line and the steps marking the individual bid prices) somehow constitute overpayments to winning QFs. Under a first-price auction, these advocates claim, those dollars would be captured by the purchasing utility for the benefit of its ratepayers.

The fallacy in this claim is that it supposes that bidders will submit the same bids regardless of the choice of auction format. This is not the case.

The bidder in a second-price auction has a strong incentive to bid a price reflecting its true marginal cost, no more and no less. This is because the second-price auction ensures that the bidder gets *more* than its bid if it wins. As long as the bid is based on the bidder's best estimate of its true marginal cost, the bidder maximizes its chances of winning, consistent with receiving a price that exceeds its cost (in other words, yields economic rents), which is what originally motivated the bidder to compete

in this market. The result is that the second-price auction reveals bidders' relative costs quite accurately and awards contracts to the low-cost bidders.

The bidder in a first-price auction has a strong incentive to bid *more* than its marginal cost, in fact, to bid strategically to come in just slightly under what it anticipates to be the lowest losing bid. Such strategic bidding has two consequences.

The first consequences is that under a first-price auction, bids are *higher* than under a second-price auction. The result is that the *average* price paid under a first-price auction is about the same as the uniform price paid under a second-price auction. This "revenue equivalence" is illustrated by Figure B adapted from PG&E witness Kahn's testimony. The "average price" in Figure B is identical to the "uniform price" in Figure A.

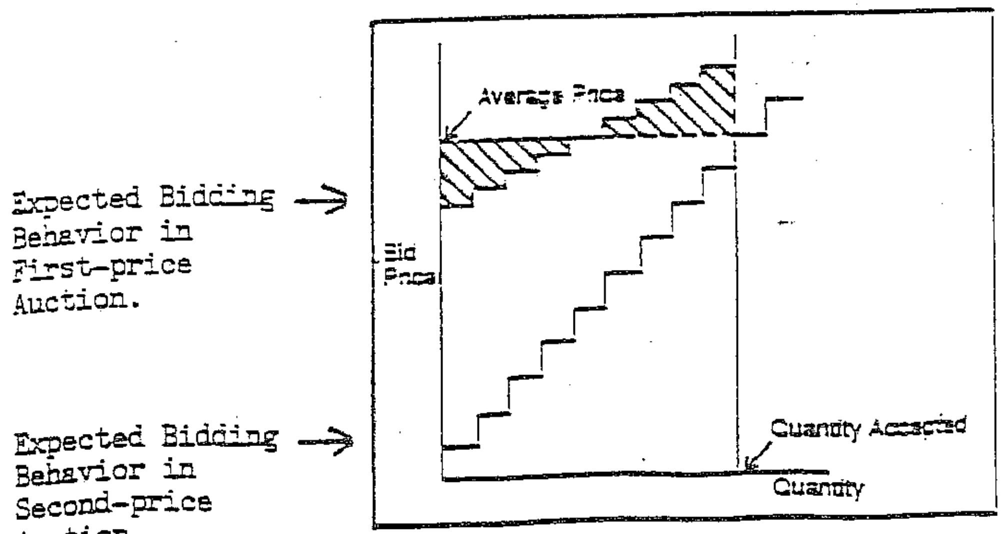

Figure B

The second consequence is that the first-price auction doesn't necessarily award contracts to low-cost bidders, but rather to bidders who are good at guessing how much to inflate their bids and still win.

Both of these consequences strongly support our preference for the second-price auction. If the expected revenue equivalence occurs, then the first-price auction will reduce competition over the long term without any off-setting short-term savings. But the inefficiency of potentially awarding contracts to higher-cost bidders concerns us even more. A producer's costs measure its consumption of goods and services in the production process. A bidder with relatively high costs is using more of society's scarce resources — burning more fuel, using more materials, possibly dirtying more air — than a lower-cost bidder.

The efficiency of the second-price auction in choosing low-cost bidders chiefly motivated us to adopt it in D.86-07-004 (21 CPUC 2d 340, 76 PUR4th 1 [1986]). Nothing since then has made inefficiency a better deal.

C. *Theory vs. Practice: Do Bidders Ever Reveal Their Costs?*

PG&E witness Kahn cites the literature supporting the revenue equivalence theorem, and his figures used above nicely illustrate its operation. But Kahn believes strategic bidding will also occur under a second-price auction, nullifying the advantages of that auction format.

Kahn argues that a winning bidder will never want to reveal any economic rent inherent in its bid price through truthfully revealing its own marginal costs in its bid. The reason is that the winning bidder still has to deal with suppliers of fuel, equipment, labor, and construction services. Some of these suppliers may have some degree of market power, such that they can counteract the economic rent that the bidder has captured by winning the auction. Worst of all, the bidder still has to face government permitting agencies:

> "Clearly, government agencies have market power over electricity supplies. The market power of government agencies is not motivated by profit maximization, as in the private sector. Rather, government agencies seek to maximize the social benefit of regulation . . .
>
> "Imagine how these negotiations would progress if the developer were the winner of a second-price auction. The government agency, would say, to the developer that his revealed 'true cost' shows he can clearly afford all the proposed mitigation and more. Indeed, the amount of money 'on the table' revealed by the auction could influence the amount of control the government agency deems required. Surely it is no longer a remarkable proposition to assert that government agencies have a tendency to spend all available money. It is difficult to imagine that this scenario would not occur to a bidder in a second-price auction. The decision to adjust true cost for this kind of rent extraction is just normal business procedure." (Exhibit 208, pages 8-9.)

As to Kahn's points--regarding supplier markets, we do not believe that potential bidders are helpless in the face of potential predation by suppliers. Surely, a prudent bidder — *regardless of auction format* — would negotiate with suppliers before submitting its bid. Furthermore, electricity auctions and requests for proposals, here and in other states, have attracted capacity offers far exceeding the capacity requested, often by a factor of 10 or more. This fact suggests that many bidders are convinced they can keep the economic rents from their electricity sales.

Neither Kahn nor anyone else in this proceeding provided evidence on the degree of market power exercised by suppliers. However, there is good reason to think that supplier markets are themselves becoming more competitive, in part because of regulatory action by this Commission regarding natural gas and transportation. The case that relevant suppliers are in a position to extract a winning bidder's economic rents hasn't been demonstrated.

Turning to Kahn's critique of government agencies, we agree that excessive costs imposed on any project by regulators can be a serious problem. Such costs may result from undue delay, conflicting regulatory signals, or inappropriate mitigation measures, and they are a risk for both QFs and utilities.

California policy-makers are sensitive to the problem. The CEC, which provides one-stop siting for major thermal power plants, was created in part to reduce or eliminate such costs; the Permit Streamlining Act is another legislative response to the problem. Our joint effort with the CEC to coordinate QF procurement with the CEC's integrated assessment of need is similarly motivated.

Of course, we may differ with PG&E witness Kahn on what regulatory costs are excessive. The polluter is often able to externalize the costs of its emissions, but in the BRPU we are trying to internalize such costs in the resource procurement process. This is similar to a principle we try to apply in rate design, namely, that the person causing specific costs should bear them. We think this principle is entirely consistent with a market-oriented philosophy of regulation.

Whether regulatory costs are adequately controlled in California is a matter of opinion. The more important point is that they are real costs that we fold into our resource procurement process: The IDR's estimates include estimated costs for permitting and environmental mitigation. Those estimates are known to the bidder in advance, and the bidder can make its own judgment of siting risks compared to those of the IDR.

Siting risks thus seem similar to all the other costs of a project that can't be known with certainty. In a first-price auction, the bidder would likely add a premium to its risk assessment; in the second-price auction, the bidder's incentive is to bid realistically.

D. *Theory vs. Practice: Is Electricity Too Complex a Commodity for Uniform Price Auctions?*

PG&E witness Kahn and Edison witness Jurewitz argue that uniform pricing is appropriate only for simple commodities. Kahn cites wheat: One bushel is perfectly substitutable for another, he claims. In contrast, any given kilowatt-hour is made up of indivisible "joint products" and may have more or less social value than another, depending not only on its price but also on the fuel used to generate it, the emissions associated with its generation, the reliability, timing, and location of its delivery to the utility, etc. Jurewitz testifies that we should be looking for the highest valued kilowatt-hours, price being only one component of value among others, and that, compared to uniform pricing, "the first-price auction environment is a lot friendlier [to] an auction process that awards bids to low-cost bidders and not just low-priced bidders." (Reporter's Transcript (RT) 1819-20.)

These arguments against the second-price auction recall the utilities' former resistance to paying QFs at full avoided cost, which is also a uniform price system. We endorsed full avoided cost pricing more than a decade ago (D.91109), even before the FERC adopted it in the regulations implementing PURPA. Full avoided cost was adopted for many reasons, including our desire to simulate a competitive market. The second-price auction is the logical extension of full avoided cost, with the lowest losing QF replacing the IDR as the price benchmark whenever QFs offer more capacity than the utility seeks.

Paying QFs full avoided cost has *never* required us to ignore differences in value between the output of different QFs. For example, we time-differentiate capacity and energy payments seasonally and by time of day to reflect the higher value of capacity and energy during peak periods. As-available QFs receive less favorable pricing terms than QFs committed to provide firm energy and capacity. Firm QFs must provide upward dispatchability. The firm QF can also get a bonus for high reliability but suffers a penalty if it falls below minimum reliability.

Other contract provisions are designed to increase the value to ratepayers of QF output. For example, there are performance requirements relating to system emergencies and coordinated maintenance. Special pricing and curtailment provisions apply when the purchasing utility experiences negative avoided cost or hydro-spill conditions on its system.

These are all features of the short-run standard offers, and the performance requirements and pricing signals folded into the long-run final Standard Offer 4 are even more extensive. We can easily add more features to this structure as we refine our QF solicitation to consider differential impacts on such things as transmission costs, environmental quality, and fuel diversity. All that is necessary is that the QF know before bidding what costs it will be expected to bear and how the benefits that it offers the ratepayer will be scored by the utility. In other words, the auction rules must be "transparent," a principle that we have already endorsed together with the second-price format.

We question whether the "joint products" associated with electric generation are particularly unusual or problematic. Of course, society is concerned with how electricity is produced and how and where it is delivered — but the same is true of wheat.[36] Possibly no commodity is simple if one examines it closely.

Any shopper knows that cheap goods are not necessarily the best bargain. We agree with Edison witness Jurewitz that the objective here should be to select those bidders offering the highest value. The second-price auction is well-adapted to achieving that objective.

E. *Theory vs. Practice: Why Aren't There More Second-Price Auctions?*

The other main argument offered by proponents of discriminative pricing is a simple nose count. Most states considering the issue have opted for a first-price auction. Nevertheless, economic literature continues to support uniform price auctions, and the National Regulatory Research Institute (NRRI) recently published a study endorsing that format for electric generating capacity solicitations.[37]

We think reasonable people may differ over the relative merits of uniform pricing versus discriminative pricing. It is clear that uniform pricing is appropriate here, where we are trying to foster competition. Even in other contexts uniform pricing is not exotic and is often proposed by utilities themselves.

For example, we have a storage banking program for natural gas, in which utilities make available a portion of their underground storage capability to accommodate customer-owned gas. Space is allocated and priced uniformly under an auction format proposed by PG&E and approved in D.88-11-034 (29 CPUC 2d 499, 507-08, 97 PUR4th 389 [1988]). The format determines a "reservation fee" that looks much like a market-clearing price (it simultaneously allocates and maximizes reservation of available banking capability), and could be lower than the price that the banking customer is willing to pay for the volume awarded. Both features resemble our second-price auction for electric generation.

Another striking proposal by PG&E is now pending in Order Instituting Rulemaking (R.) 88-08-018, where we are considering possible ways to allocate pipeline capacity controlled by gas utilities to those utilities' transportation customers. Pipeline capacity allocation is complicated because there are many paths and many constraint points between any given source region and the California delivery point. PG&E proposes a "sophisticated form of auction . . . because of the multi-dimensional nature of the problem, and the objective of maximizing value to customers." The proposal is for a uniform price auction: "[T]he price charged the successful bidders will be set by charging the competitive equilibrium (market-clearing) price for capacity at each bottleneck and summing those prices along the paths." PG&E notes that, "in general, the price paid will be lower than the bid price."[38]

In PG&E's pipeline capacity proposal, as in our second-price auction, a pricing system that seeks the market-clearing level is preferred to one that would maximize monetary gain to the party soliciting the bids. Moreover, the complexity of the auctioned commodity is seen, not as a bar to a uniform price auction, but as part of the justification.[39]

Choosing an auction format requires vigorous analysis and close inspection of ends and means. We are satisfied with our choice and do not find a nose count of other jurisdictions either persuasive or illuminating.

F. *Conclusion*

Our thorough scrutiny of auction format in Phase IB should put this issue to rest.

We recognize, however, that auctions are not the only model for competitive procurement. We have long encouraged arms-length negotiations between our utilities and potential sellers of electricity, not limited to QFs. We have even predicted (in D.86-07-004) that such negotiations, over time, will increasingly displace the standard offer as QFs' preferred means for contracting. This displacement depends on progress on outstanding issues regarding transmission access and evaluating resource options. (See Section III above.)

First, QFs still lack assured access to potential markets. We look to our wheeling/transmission cost allocation investigation (I.90-09-050) for solutions that substantially increase such access in time for its impact to be felt in the auction for this ER/BRPU cycle.

Second, there is still much work to do to ensure that the ratepayer is getting (and offering) reasonable value for QF generation. We have now made a start at valuing "adders" for system stability and load following features, environmental impacts, and fuel diversity. All of these must also be analyzed and compared on a consistent basis with DSM programs. We are committed to completing this work, but it will require strenuous effort throughout the next ER/BRPU cycle.

The rewards for success in these endeavors will be substantial: a fully established independent power industry and an electric resource procurement process that is finely-tuned and market-responsive. We hope at that time to be able to dispense with Commission-supervised auctions, and possibly even with the BRPU itself.

In the meantime, we will monitor the results around the country of this and other competitive solicitations for electric generation. Should we find solid evidence that the second-price auction is not producing the benefits we have described, we will reconsider in later updates our choice of the second-price auction.

VII. *Significance of the IDR Benchmark Price*

[15] In the final Standard Offer 4 auction, QFs bid to beat a utility avoided cost benchmark computed from the projected capital and running costs of the IDR. The second-price auction rules require that QFs displacing the IDR receive payments computed from the lowest losing QF's bid if there is an "oversubscription" (the capacity of QF bidders exceeds the capacity of the IDR). If there is an undersubscription, all bidding QFs are winners and receive payments computed from the full projected costs of the IDR. In the sense of being the potential auction price-setter, the IDR can be considered the utility's bid.

But suppose that the utility actually builds the IDR, as might happen, for example, if the auction were undersubscribed: Is the utility in that situation bound to build the IDR for the capital costs indicated in the benchmark price? In other words, should the benchmark price be treated as the utility's bid for purposes of setting rates to recover utility investment in the IDR?

QFs and DRA argue that the answer should be yes. They believe the IDR benchmark would not be credible if the utility itself were not constrained by the benchmark price. The presence of such a constraint would give utilities a strong incentive to carefully investigate the costs of potential IDRs. The lack of such a constraint, according to QFs and DRA, would give utilities a chance to manipulate cost data and, consequently, the determination of need in the ER/BRPU cycle.

The utilities, supported by the CEC, argue that the answer should be no. The utilities maintain that precise estimates for a large number of IDRs — the kind of estimate they would make before committing to build a given power plant — are costly, time-consuming, and more exact than necessary for the purpose of identifying deferrable resources. They note that California law already requires the CPUC to establish a cost cap for a utility power plant in issuing a certificate of public convenience and necessity for the plant. (Public Utilities Code § 1005.5.) Finally, they believe that treating the IDR benchmark as the utility bid would be unfair. This is because, in their view, the utility would be at risk for cost overruns, like QF bidders, but unlike QF bidders the utility could not earn more than its authorized rate of return if it managed to build the IDR for less than the benchmark price.

We have decided not to treat the IDR benchmark as a binding cost estimate on the utility at this time. There are good arguments on both sides of this issue. In particular, exact estimates of IDR costs are critical, but we believe the ER/BRPU cycle already contains adequate safeguards to ensure the credibility of the IDR benchmark.[40]

Deliberate manipulation of the IDR benchmark by the utilities would be difficult, given the public scrutiny that cost estimates receive here and at the CEC. Moreover, the utility has a strong incentive to be accurate. Low cost estimates would cause more new resource additions to be found cost-effective and potentially deferrable by QFs, so this strategy could result in more QFs in the utility's resource mix, not fewer. High cost estimates would result in fewer IDRs but increase the likelihood (given the inflated benchmark price) that QFs would fill all identified need, so the utility would never get to build the IDR. Finally, we expect the utility to explain any inconsistency between resource assumptions it uses in the BRPU and those it uses in other proceedings. Thus, "gaming" the BRPU estimates is unlikely to go unnoticed and could jeopardize the utility case in matters outside the BRPU.

Another important consideration is that the utility is *not* "committed" to build the deferrable resource as of the date it is identified. Following our decision specifying IDRs in the planning phase of the Update, the utility puts together and publishes its formal QF solicitation. There follows a three-month solicitation period during which QFs submit sealed bids. Only after the bids are opened and winners designated does the utility know how much of the identified need will be deferred through QF contracts. Depending on the result of the auction and possibly other changes of circumstances, the utility may build the IDR, downsize the IDR, build some other resource, pursue a combination of strategies, or wait for the next Update. Whatever the utility decides, we would review the reasonableness of its decision based on the circumstances existing when the decision was made. That could follow the specification of IDRs by several months. In all likelihood, the utility would not pursue the IDR exactly as proposed in the Update because QFs would be deferring some substantial portion of the need. How to apply the IDR benchmark as a binding cost estimate in these circumstances is unclear.

On balance, we think the ratepayer is well served by reasonableness review and cost caps developed pursuant to Public Utilities Code § 1005.5. If experience shows that cost estimates in the BRPU are unrealistic, we may reconsider the question of whether and how to hold the utility to the benchmark price.

VIII. *Eligibility to Bid*

[ii] Currently, only QFs may bid in the final Standard Offer 4 auction. We will retain this limitation for the time being, but we intend to move toward "all-source" bidding.[41] This move depends on making significant progress in evaluating non-price factors and in allowing nondiscriminatory access to electric transmission services ("wheeling") for nonutility power producers.

To recapitulate our reasoning in Section III above, both the bases and avenues of competition must be firmly established before QFs will be able to compete directly with traditional utility supply options. These conditions are necessary for a competitive market to exist. Absent these conditions, the results of all-source bidding would be renewed reliance on traditional supply options.

On the other hand, we have no desire to continue restrictions on bidding eligibility any longer than necessary. Work in the Update and the transmission investigation is intended to remove the block to full competition in electric generation. To the extent that the work is successful, competition truly would increase through broader participation in the auction.

The work will not be completed overnight. It is also conceivable that progress will come in stages. For example, parties' comments in I.90-09-050 indicate that wheeling service is likely to be subject to various limitations and that some kinds of wheeling may be harder to provide than others. Similarly, some non-price factors may prove more elusive to evaluate than others. The question, then, is how we should react, in terms of auction modifications or otherwise, to partial progress on these tasks.

We may be able to limit controversy in future Updates by establishing a set of check points to elaborate on our broad policy discussion in Section III. The check points would link specific modifications to final Standard Offer 4 with specific achievements in providing transmission-only service and evaluating non-price factors. The purpose would be to create a common understanding of where we are heading and how to get there.

The Phase 1B record does not enable us to establish check points in this decision. Instead, we direct the assigned ALJ to solicit the parties' input at a prehearing conference to be held before the start of the ER-90 phase of this proceeding.

Powerex, in its comments on the ALJ's proposed decision, says that there are Canadian entities who meet the PURPA and FERC requirements for QF status but who might be excluded from the auction because FERC can only certify as QFs entities inside the United States.[42] Powerex believes such an exclusion would lack any sound policy basis and would violate trade agreements between the United

States and Canada.

We agree with Powerex that foreign entities meeting all requirements for QF status other than FERC certification should probably be eligible to bid along with duly certified QFs.[43] However, the purchasing utilities, in lieu of such certification, must have a suitable alternative means of ensuring that the foreign entity meets all other requirements for QF status initially, and maintains its compliance throughout the term of the contract, as would be required of a U.S.-based QF.

We do not not know whether the Canadian government has, or would wish to carry out, a program functionally the equivalent of FERC certification. We believe such a program may not be necessary if appropriate contract provisions, applicable to foreign entities, could be crafted for final Standard Offer 4. We will hold workshops to develop various contract modifications in response to today's decision, and we encourage the parties at the workshops to draft proposed provisions accommodating bidding by foreign entities that meet the requirements for QF status.

IX. *Power Purchases Between Updates*

[16] We asked the parties to make recommendations in this phase on how QFs can effectively compete with power purchase opportunities that arise between Updates. We were concerned that, for various reasons, significant opportunities might be lost if all such opportunities were required to undergo analysis as potential IDRs in an Update; but we were also troubled by the prospect of utilities committing for much of their resource needs without such analysis. Our review of the various recommendations convinces us that the present system is reasonably good and requires little if any modification.

A. *Positions of the Parties*

Generally, the BRPU process places few constraints on the utilities' ability to make power purchase commitments between Updates.[44] We do not approve such commitments prospectively but review the reasonableness of resulting power purchases in subsequent proceedings.

1. *Checks on Utility Discretion*

The QFs believe that utilities have too much discretion between Updates. For example, CEERT says "All inter-utility contracts should be subject to displacement by QF purchases. Similarly, any utility efforts to acquire long-term resources between [Updates] should automatically trigger a new final Standard Offer 4 solicitation. Without such safeguards, utilities have too many incentives to 'game' their ICEM analyses and IDR cost estimates. . . ." (Exhibit 228, page 12.) GRA/IEP express similar views.[45]

The utilities appreciate the ability to sign contracts between Updates but feel that the present system still creates difficulties. The limited experience to date indicates that a new BRPU or Electricity Report, and sometimes both, will always be in progress at any given time. The utilities believe that, as a result, a power purchase commitment made outside the Update will be attacked as premature or a device to avoid competitive bidding by QFs. Furthermore, the utilities urge that short-term purchases (five years or less) be considered nondeferrable.

PG&E and SDG&E address these problems by proposing that a long-term power purchase contract between Updates be deemed reasonable and nondeferrable if it meets a stated price threshold. For example, under the SDG&E proposal, any such contract whose price is at or below 90% of the final price to QFs as determined in the most recent Update (or 90% of the long-run avoided cost projection in that Update if no QF contracts were awarded) would be deemed nondeferrable and would not be subject to reasonableness review. Any contract whose price exceeds the threshold would be subject to reasonableness review.

DRA also supports the threshold concept but would have separate thresholds for short- and long-term contracts, and would subject any non-price terms of these contracts to the usual reasonableness review.

2. *Impact on Non-QF Resources*

All parties accept that a power purchase can be an IDR. However, some parties claim that the present system inhibits some potential sellers from reaching their bottom line before the Update. Also, the utilities say that an offeror is unlikely to leave an offer on the table for QFs to bid against. This raises the issue of determining when the terms of a potential power purchase have achieved sufficient definition for that purchase to serve as an IDR.

In the CEC's view, the problem of contracts between Updates is simply one aspect of the more fundamental problem that the Update presently limits bidding to QFs only: "The real problem is not that options may arise between updates, but that the current process does not provide any mechanism for allowing resources other than QFs from competing directly for the right to meet the utilities' needs." (Exhibit 224, page 29.) According to this testimony, DSM and utility plants are among the resources that "cannot compete against a QF in the current system." (*Id.*)

B. *Discussion*

The fundamental purpose of the BRPU is to implement a long-run standard offer at a level of potential commitment to QFs that both this Commission and the CEC believe is consistent with the need for electricity in California. Such implementation requires us to make a coordinated review of the resource plans of the major investor-owned electric utilities. The integrity of this process also requires that utility actions taken between the coordinated review be consistent with the assumptions and policies that form the basis of the utilities' resource plans. Thus, the utilities must either use the same assumptions or identify and justify, in whatever forum such utility actions are reviewed, any departure from those assumptions.

We can achieve this fundamental purpose without either freezing utility commitments between Updates or requiring some sort of auction procedure every time a resource opportunity arises. So long as utilities observe the rule of consistency that we just described, a utility should be able to consummate a deal when the utility thinks the time is right. There is nothing to the contrary in any of our prior decisions in this proceeding. The QF proposals are generally too restrictive and are rejected.

On the other hand, the reasonableness thresholds proposed by PG&E, SDG&E, and DRA are unnecessary and undesirable. The problems that a utility encounters in justifying a power purchase are not simply a function of the QF program. A utility could always be second-guessed as either committing prematurely or settling for less than the best deal.

The task of demonstrating reasonableness properly falls on the utility, and it is not our responsibility to find ways to make that demonstration easy. We certainly expect that reasonableness review will cover the timing of the utility commitment, including the issue of whether the price or other terms of an offer were so good as to justify the utility's decision not to risk the lapse or withdrawal of the offer by treating it as an IDR in an Update.

Furthermore, the threshold proposals violate an important regulatory principle: The reasonableness of a utility decision depends on things known or reasonably knowable by the utility when the decision was made. In contrast, the thresholds do not depend on current information but instead relate back to long-run avoided cost projections made during the most recent BRPU. We hope and expect that those projections will not be highly sensitive to short-term phenomena such as might arise during the ER/BRPU cycle, but we nevertheless require the utility to act on the best information currently available to it.

Neither we nor the parties can possibly foresee the vagaries of the energy market next year or the year after. We stress that utility management retains the discretion and the responsibility to respond to that market.[46]

Thus, we neither increase the current constraints on purchases between Updates, nor do we approve price thresholds to provide advance assurance of reasonableness for such purchases. There will be time to consider appropriate constraints if and when we have evidence that utilities are abusing the considerable discretion they now have.

We note that the utilities may have means to test the waters between Updates short of a full-scale final Standard Offer 4 solicitation. For example, GRA/IEP suggest as a model the recent contract between Edison and the Bonneville Power Administration. As described by GRA/IEP witness Branchcomb, QFs had an opportunity in A.88-10-048 to comment on Edison's proposed purchase; they responded that the purchase terms were not likely to be matched or beaten in a QF auction.[47]

An application should not be necessary, however a utility that believes negotiations have reached an appropriate stage could contact individual QFs and QF groups, stating generally the anticipated terms and seeking expressions of interest. It should be to California utilities' advantage to use QFs to prompt better terms from non-QF sellers, and we expect our utilities to exercise their ingenuity in making this happen.

Turning to the CEC's comments, we have explained above in Sections III and VIII why we continue to limit the final Standard Offer 4 auction to QF bidders. The present industry structure simply doesn't enable QFs (or DSM) to compete directly with other resource options; nevertheless, the ER/BRPU process preserves a niche for QFs and DSM without disabling the utilities from pursuing the universe of resource options.

ER-90 ensures that DSM will far predominate over generation options, however. This is accomplished through the category of "uncommitted DSM," which consists of programs that are not currently in place but that the CEC expects to receive regulatory approval during the forecast period. (See ER-90 at page 4-12.) Table 6-2 of ER-90 identifies a new resource need of 2,694 MW for PG&E by 1999, of which 2,506 MW (93%) is to be filled by uncommitted DSM. The CEC's need assessment for Edison likewise assumes that most resource need (about 72%) will be filled by uncommitted DSM. (ER-90, Table 6-5.)

Planning for QFs (BRPU's fundamental purpose) involves the whole resource plan, including DSM. We have previously expressed concern over the way the CEC handles uncommitted DSM.

For example, in our first Update, we agreed with criticisms over the determination of such DSM in the CEC's Sixth Electricity Report, but we accepted the CEC's forecast in preference to the position of parties who would have totally excluded uncommitted DSM from the base case resource plans. We strongly endorsed the goal of ensuring that "the benefits of all resource options, to the extent they are quantifiable, are quantified on a common basis, and to the extent that qualitative judgments must be made, that the qualities are identified in advance." D.87-11-024, 26 CPUC 2d 62, 71 (1987).

We have not yet reached that goal, but we have taken initiatives to pursue conservation opportunities aggressively. With the CEC's active participation and support, we have created incentive programs for electric utilities that for the first time give those utilities a positive stake in the success of conservation efforts. Together with the CEC, we have refined the Standard Practice Manual that is used at both agencies to test DSM programs for cost-effectiveness. The Standard Practice Manual does not analyze generation options, so we have directed the utilities to explore the capabilities of ICEM for testing DSM together with generation resources. Again, we welcome and solicit the CEC's input, since a primary purpose of these explorations is to help the two agencies reach agreement on appropriate DSM levels.

This Commission's ultimate goal is direct competition among all generation options. Eventually, generation and DSM may also compete directly, and the basis for reserving some portion of need for particular resource categories may vanish. Until then, regulators must ensure that traditional utility resources still retaining market power do not displace cleaner, smaller, more efficient alternatives.

X. *QFs Entitled to Switch to Final Standard Offer 4*

A few QFs, dating back to the time when we were first developing standard offers, are operating under contracts with provisions that entitle them to switch to final Standard Offer 4. These provisions were incorporated in early power purchase agreements at our direction in order to spur the development of the independent power industry.

These QFs have been waiting as much as a decade, which is approximately how long it has taken for us to develop final Standard Offer 4 and for new capacity needs to appear. We did not allow these QFs to switch to interim Standard Offer 4, but we made clear when we adopted the second-price auction that these QFs do not count against the MW limits and are not required to bid. They are affected by the second-price auction only to the extent that, like the winning bidders, their price is set by the lowest losing bid. If they are dissatisfied with the price, they need not exercise their right to switch but can wait for an auction in a later Update.

Modifications to the existing auction format may complicate the switching process. For example, if we were to adopt a discriminative auction, there would likely be many different winning prices. Which price does the switching QF get? How is the switching QF's price affected if residual emissions are factored into the bidding system?

In the future, parties proposing changes to final Standard Offer 4 must indicate how switching QFs would exercise that right under their proposals. We will not entertain any proposal that would require such QFs to submit competitive bids. Such a proposal would have the effect of retroactively limiting the QFs' contractual right to switch.

We are today adopting a modification to the existing format. As described previously, the second-price auction now requires a bid with separately stated energy and capacity prices; the actual capacity price that a winner receives is determined from its energy price and the result of the auction. We propose the following procedure for switching QFs and invite comment on the procedure in the next phase of the Update.

Under our proposal, switching QFs would submit an energy price under seal. After the utility announces the auction result, switching QFs that choose to exercise their right would tell the utility to unseal their submitted energy prices and compute a capacity price using the same calculation methods applicable to winning QFs. A QF that chooses not to switch after the announcement would so notify the utility, which would immediately return the QF's energy price submittal *unopened*.[48]

No environmental adder or subtractor would apply to payments under final Standard Offer 4 to a switching QF. Such QFs get the price resulting from the auction without having its own residual emissions compared to those of the IDR. This follows from the fact that the switching QF is an existing resource and, unlike the winning bidders, is not deferring or avoiding the IDR. Stated differently, the QF that is contractually entitled to switch has the same impact on system emissions whether or not it exercises that right. For similar reasons, switching QFs do not qualify for a fuel diversity premium.

XI. *Bidding by Standard Offer 1 QFs*

[17] PG&E proposes that, pending further study, QFs currently holding Standard Offer 1 contracts be barred from participation in final Standard Offer 4 bidding. PG&E concedes that such QFs are eligible to participate under current rules, but asserts that ratepayers might realize significantly higher benefits from new QFs winning the final Standard Offer 4 auction as compared to winning Standard Offer 1 QFs.[49] Standard Offer 1 does not contain a contractual right to switch to final Standard Offer 4, so PG&E's proposal effectively bars all Standard Offer 1 QFs from ever bidding for a final Standard Offer 4 contract, except perhaps through negotiation with the utility.

No other party supports PG&E's proposal, while DRA and Chevron actively oppose the proposal.

We have no desire to "freeze" the status of Standard Offer 1 QFs. In fact, to the extent that such QFs are technically and otherwise able to provide firm energy and capacity, they should be encouraged to do so and should have access to appropriate contracts for firm power sales. All parties acknowledge that firm sales have greater value to the purchasing utility than do as-available sales. Furthermore, on a nameplate rating basis, a firm QF can avoid utility resources up to the full amount of the QF's

capacity commitment, while an as-available QF can avoid only its "effective" capacity.[50]

PG&E is concerned that some portion of an IDR's cost-effectiveness depends on savings attributed to lower energy payments to Standard Offer 1 QFs. *If* the IDR constitutes a significant fraction of the utility's system, and *if* the IDR is replaced by Standard Offer 1 QFs, and *if* the auction produces no discount from the IDR price, then (PG&E posits) the resulting QF mix might not be cost-effective compared to the IDR. This hypothetical concern seems very remote.

It is true that lower running costs are a major element of an IDR's cost-effectiveness, and that payments to QFs receiving short-run marginal cost-based energy payments are a major element of a utility's running costs. However, Standard Offer 1 QFs are a small fraction of the QFs receiving such energy payments, and there is no reason to think that all Standard Offer 1 QFs would be successful bidders, to the exclusion of all other bidders in a given auction, even assuming that they could satisfy the substantially more arduous performance requirements of final Standard Offer 4.

Moreover, the participation of Standard Offer 1 QFs in the second-price auction could result in a lower price to all successful bidders. In short, the analytical inconsistency identified by PG&E is unlikely to be significant and could easily be more than off-set by the benefits resulting from Standard Offer 1 QFs' participation in the auction.

Thus, we will allow Standard Offer 1 QFs to participate in the final Standard Offer 4 auction, so long as such a QF provides new capacity, e.g., by expanding its plant or committing to firm operation.[51] If that QF is successful in the auction, the purchasing utility should count the QF's capacity toward the MW limit, using the appropriate nameplate-to-effective capacity conversion factor when comparing the QF's system contribution under Standard Offer 1 and final Standard Offer 4. The QF would also receive environmental adders and a fuel diversity premium, if applicable, to the extent of its new capacity.

XII. *Demonstration Projects*

[18] Texaco proposes that this Commission implement in the BRPU one of the CEC's recommendations in ER-90.[52] Specifically, the CEC urges municipal and investor-owned utilities to consider contracts that encourage non-utility generation technology development. Such contracts, in the CEC's view, would carry a higher price tag (in proportion to the risk inherent in demonstration projects) than contracts with developers using proven, commercially available technologies; however, the CEC suggests that demonstration of new technologies is in the long-run public interest and that the public "investment" in such demonstration could be protected through appropriate licensing provisions or discounts from purchases made during commercial application. (See generally ER-90 at pages 8-9 to 8-10.)

Texaco and the CEC believe the standard offers are not suitable for demonstration projects. According to the CEC, nonstandard contracts are needed "with adequate payment mechanisms to provide incentive for such projects. Such payments could include fixed capacity and/or energy payments for the duration of the project's demonstration phase." (ER-90 at page 7-19.) Texaco recommends that these contracts be individually negotiated between the project sponsor and the utility.

Under Texaco's proposal, there would be an "allocation" in each BRPU of 300 MW for demonstration projects.[53] The allocation would be considered nondeferrable and would not be subject to the final Standard Offer 4 bidding process. Also, the allocation would be cumulative, so that if some part of the allocation were not contracted for in a given update cycle, those MW would be added to the 300 MW allocated in the next update cycle.

Texaco is *not* suggesting that these allocations be treated as a set-aside: In other words, non-utility demonstration projects would not bid against each other in a separate forum, nor would the contracts awarded under the allocation count against the purchasing utility's need for new resources, as determined in the BRPU. Eligibility for the allocation would be contingent on a determination by the CEC that the candidate project is a "research, development, or commercial demonstration project" within the meaning of Public Resources Code § 25540.6(e).

Other parties withhold judgment on Texaco's proposal. DRA and the CEC believe a complete resolution of issues relating to demonstration projects would greatly exceed the scope of Phase 1B. They are right. Texaco's position has some relevance to such Phase 1B issues as the ER-derived base case and power purchase opportunities arising between updates. Our discussion here does not purport to be a comprehensive approach to the regulatory and ratemaking treatment of non-utility RD&D.

First, we agree that any demonstration project should not count against "need" for purposes of BRPU. A utility fills need with dependable resources. A technology still in some stage short of successful commercial demonstration may well prove dependable, but there is no assurance that it will. Thus, we are unwilling to allow demonstration projects to defer other resources.

Second, ER-90 recommends that "these special contracts be made available to *no more than 300 MW*. . . in any Electricity Report cycle." (ER-90 at page 8-10.) The potential under Texaco's cumulative allocation proposal for a huge number of MW in a single ER cycle is risky and inconsistent with the CEC's recommendation. Any such allocation should be noncumulative.

Third, the BRPU is not suited to determining the value to ratepayers of demonstration projects in general or of particular demonstration projects. The CEC in its demonstration siting decisions determines such issues as whether a project (1) qualifies as a demonstration project and (2) has demonstration benefits for California that justify the project's costs. These determinations should assist the project sponsor in negotiating a nonstandard contract with a utility. As DRA notes, this Commission has approved many nonstandard contracts, both before and after the creation of the standard offers. We believe our past decisions on nonstandard contracts and on utility/QF negotiations give adequate guidance for demonstration project sponsors at this time.[54]

XIII. *Consideration of Uncertainty and Strategic Preferences*

[19] All resource planning decisions deal implicitly or explicitly with uncertainty.[55] Dealing with uncertainty generally requires formulation of a strategy based on the risk preferences of the decision-maker. Our experience with long-run standard offers teaches that uncertainty should be dealt with explicitly in the planning process, that known risks should be quantified, and that strategic elements should be built into the resource plan to respond to those risks.[56]

The controversy concerning uncertainty analysis is not whether but where to do it. The CEC recommends that all such analysis be confined to the ER process as part of the CEC's integrated assessment of need. If changes occur following adoption of an ER, such that the analyses and conclusions require revisiting, then the CEC suggests "a cooperative process with the CPUC" whereby the CEC could tailor its consideration of these changed circumstances "to meet the immediate needs of the BRPU's acquisition process. [But the CEC opposes] any procedure that automatically and routinely invites the [ER parties] to relitigate, in the BRPU, the need assessments and uncertainty issues that are fully examined and decided in the [ER]." CEC Phase 1B Concurrent Brief, pages 32-33.

All other parties taking a position on this issue oppose the CEC. PG&E puts it most succinctly in advocating that "any Commission which performs resource planning analysis should also conduct uncertainty analysis." PG&E Phase 1B Concurrent Brief, page 101.

We have decided to continue including uncertainty analysis and strategic preferences in our consideration of resource plans in the Update. This decision could easily be misconstrued, so we begin by correcting two faulty perceptions regarding our relationship with the CEC.

First, the CEC and the CPUC are not engaged in a tug-of-war over electricity resource planning. The task is to coordinate the two agencies' resource planning efforts. Starting with D.86-07-004, the CPUC has committed

to make final Standard Offer 4 solicitations consistent with the CEC's assessment of need in its current ER. Both agencies agree that achieving the "consistency" we seek has both procedural and substantive aspects. For example, CPUC determinations in various proceedings on utility costs and rate design must feed into the ER process, just as CEC projections of supply and demand in the ER must feed into the BRPU. We will have more to say below about consistency. The point for now is that the present dialogue on this subject has been going on for some time and has been actively encouraged by both agencies. It has produced better understanding, increased direct participation, and improved information flows at both agencies, and California resource planning is the better for it.

Second, we do not intend, under the rubric of uncertainty analysis, to undermine the ER-90 forecasts or somehow compensate for perceived deficiencies in the ER process. ER-90 is the third Electricity Report to involve coordination with final Standard Offer 4. During that time, the CEC generally has been responsive to our BRPU decisions and has refined the ER process in ways that answer many of our concerns. There are many examples: the common use of ICEM at both agencies, improvements to the analysis of aging power plants, the CEC's own analysis of uncertainty, and the progress in evaluating non-price factors, to name a few. Not long ago, the CEC and the CPUC treated resource planning in different ways using different terminology. Increasingly, the ER/BRPU cycle uses shared analytical tools and a common language to address what both agencies believe to be the key issues.

Nevertheless, the CEC and the CPUC perform different functions in relation to resource planning. As long as that is so, the translation of ER findings into a final Standard Offer 4 solicitation can never be wholly ministerial.

The CPUC is charged with establishing just and reasonable utility rates. It projects utility costs, computes the revenue requirement, and creates rate schedules to meet that requirement. These responsibilities explain why the CPUC and not the CEC has always conducted the QF program, since it is the CPUC that determines the marginal utility costs from which avoided cost payments to QFs are calculated. It is also the CPUC, and only the CPUC, that can review the reasonableness of utility expenses.

Given our obligation to ensure that utility rates are just and reasonable, we are also obliged to ensure that the resource plans on which final Standard Offer 4 solicitations are based incorporate appropriate hedging strategies. Such strategies will protect ratepayers from undue exposure to increased costs, should the future differ from our forecasts, as it surely will to some degree. (Cf. D.88-19-026, 29 CPUC 2d 263, 272-73 [1988].)

We would want to do some analysis of uncertainty and consideration of hedging strategies even were we to agree entirely with the ER "base case" resource planning assumptions and subsidiary findings. Here, we have reached different conclusions from ER-90 on several matters, most importantly, how to pay final Standard Offer 4 QFs and how to value air quality and fuel diversity. These are further reasons why the utility compliance reports should contain uncertainty analysis that responds to our directions here as well as assumptions from ER-90.

For several agencies to perform somewhat overlapping analyses is not a planning failure, it is inevitable in something with as many complex ramifications as electricity resource planning. Indeed, resource planning can be no one agency's exclusive domain. Each of these entities—the CEC through forecasting and energy efficiency standards, the CPUC through ratesetting, the Air Resources Board and local air management districts through air quality regulations—strongly and legitimately affects resource planning. Each agency has its own perspective, conditioned by its own expertise and statutory mission. As joint problem solvers, we can ensure that resource plan "solutions" are sufficiently robust to meet the many goals and programs electric utilities must satisfy.

In conclusion, the utility compliance reports in the next phase of the Update will reflect directions in this decision and in D.90-03-060 (36 CPUC 2d 2 [1990]) (our Phase 1A decision) to the extent such directions differ from ER-90. We expect that these differences may affect the type and timing of IDRs and possibly suggest different hedging strategies. However, we also expect to meet our commitment to tailor the ensuing QF solicitation to ER-90's integrated assessment of need. The "barebones" analysis, which is ICEM's starting point, should draw its demand and fuel price forecasts for each utility from ER-90 (cf. D.90-03-060, 36 CPUC 2d 2, 48-49 [1990]), and the total MW in the solicitation should not exceed the needed capacity identified by the CEC for each utility over the next eight years in ER-90. (Cf. D.86-07-004, 21 CPUC 2d 340, 373 [1986], and D.88-09-026, 29 CPUC 2d 263, 272-73 [1988].)

XIV. *Status of Standard Offer 2*

[20] We asked the parties in this phase of the BRPU to make recommendations on the future role of Standard Offer 2. We agree with the general consensus that final Standard Offer 4 should be our primary instrument for directly involving QFs in resource procurement. We do not rule out reinstating Standard Offer 2, provided that such reinstatement is accompanied by certain modifications, and is for a limited amount of time and capacity. Standard Offer 2 may also be useful as a model for some kinds of nonstandard contracts. We do not envision making Standard Offer 2 available on an ongoing basis.

A. *Background*

Standard Offer 2 is a short-run offer in that it uses short-run principles to determine energy and capacity prices, but it has some important characteristics of a long-run offer. It is a long-term commitment by the QF. Standard Offer 2 contracts can be for as long as 30 years and cannot be cancelled at the QF's election.

Also, in contrast to the other short-run offers, the Standard Offer 2 capacity price is projected at the time the contract is signed, using the full annualized cost of a combustion turbine, and fixed and levelized for the whole term of the contract.[57] The Standard Offer 2 QF delivers "firm" energy and capacity. It is penalized for failing to meet a stringent availability requirement during the purchasing utility's peak, and it can also earn bonus payments by substantially exceeding that minimum availability requirement.

Originally, a new QF could sign a Standard Offer 2 contract at any time, and without regard either to the number of QF megawatts already under contract or on-line, or to the purchasing utility's need for new capacity. These factors led us to suspend the availability of the offer.[58] We later reinstated Standard Offer 2 but only for SDG&E. We also limited the availability of the reinstated offer to a specified time and total capacity of new QFs.[59]

B. *Final Standard Order 4 Is Generally Superior to Standard Offer 2*

Standard Offer 2 was important in the early days of the standard offers. It has a front-loaded payment structure with fixed capacity prices. Standard Offers 1 and 3 have neither feature, so Standard Offer 2 was virtually the only contract suitable for capital-intensive QFs both before the availability of interim Standard Offer 4 and after we suspended the latter offer.

Unfortunately, Standard Offer 2 suffers from the same deficiency as interim Standard Offer 4 in not being clearly tied to a determination of deferrable MW. Another disturbing aspect of Standard Offer 2 is that, although it is a long-term commitment by the utility and QF, its energy payments are tied to the purchasing utility's short-run marginal cost. This in effect increases the ratepayer's exposure to rising oil and gas prices even if the QF is not oil/gas-fired.

We have suggested previously that Standard Offer 2 might have a role to play in acquiring non-fossil QFs, at least those that could meet the offer's requirement to provide firm capacity. However, we believe that modifications made in today's decision to final Standard Offer 4 have removed any bias against such QFs, so there is no longer a special "environmental" role for Standard Offer 2 to play.[60]

C. *Future Role of Standard Offer 2*

If final Standard Offer 4 works as intended, even a limited reinstatement of Standard Offer 2 should be unnecessary. Nevertheless, we hesitate to rescind the offer entirely, given the difficulty we've experienced in developing a satisfactory long-run offer.

Should we decide to reinstate Standard Offer 2 for whatever reason, we expect that the reinstatement would be limited as it was for SDG&E. The limitations would include block pricing and caps on the time and the total capacity for which the offer would be available. Also, the fuel price risk mentioned above should be mitigated by appropriate indexing of the energy payment if the QF is not oil/gas-fired. Finally, the queue management rules should be improved to resolve oversubscription, as occurred during the SDG&E reinstatement.

We also recognize that utilities will continue to receive requests for nonstandard contracts from QF developers for whom the available standard offers are unsuitable. One example is waste-to-energy QFs. We are interested in encouraging this technology, which promises both energy and environmental benefits. However, it is a capital-intensive technology that our experience shows has a long and uncertain lead time. A nonstandard power purchase agreement drawing many of its provisions from Standard Offer 2 may prove to be the most appropriate contractual vehicle for such QFs. Our past decisions on nonstandard contracts should guide the utility and QF in negotiating such contracts.

XV. *Prehearing Conference*

Many tasks await us in the next phases of the BRPU and in our investigation of transmission wheeling service and cost allocation. Consultation with the parties is appropriate to schedule and coordinate these tasks. The assigned ALJs should promptly notice a joint prehearing conference for these proceedings for this purpose. The parties should consider the following priorities in formulating their scheduling proposals.

Our top priority in the BRPU is to make changes to final Standard Offer 4 and the auction protocol consistent with today's decision. These conforming changes should not be contentious. In the past, the utilities, QFs, and DRA have drafted the precise contract language used in the final Standard Offer 4 power purchase agreement, following general directions provided in D.86-07-004 and other decisions. The product of these drafting efforts was reviewed in the same manner as other types of stipulations and settlements, with opportunity for objecting parties to be heard. The same process should work now. Interested parties should be prepared at the prehearing conference to suggest a meeting schedule to begin the joint contract drafting effort.

Our second priority in the BRPU is to conduct the next phase of BRPU reviewing utility resource plans in response to ER-90 ("ER-90 phase"). That phase will commence with utility resource plan compliance reports filed nine weeks after the effective date of today's decision. (Cf. D.88-09-026 [29 CPUC 2d 263 (1988)] Appendix B.) We intend to complete the ER-90 phase in time for a final Standard Offer 4 auction in early 1992.[61]

The transmission investigation must be closely coordinated with the ER-90 phase of the BRPU. We anticipate issuing an interim order in that investigation soon. The interim order will analyze the initial and reply comments and the respondents' data production pursuant to the January 10, 1991 Assigned Commissioner's Ruling. We also anticipate the interim order will give general policy directions, from which the parties to the transmission investigation may rethink their own proposals and begin discussion with other parties aimed at narrowing the issues.

Our third priority in the BRPU is Phase 3, the methodology phase. We update a number of things in the BRPU besides resource plans. (See generally D.88-03-026 [27 CPUC 2d 502 (1988)].) Also, changes in natural gas regulation require some rethinking of our method for calculating short-run marginal costs. On the other hand, we do not intend Phase 3 to open up every question in the history of the QF program. In particular, *no* matter resolved in today's decision is subject to reconsideration in Phase 3.[62] Any party proposing an issue for Phase 3 shall be expected at the prehearing conference to justify inclusion of that issue, stating specific reasons demonstrating its timeliness and importance.

XVI. *Comments on Proposed Decision*

Pursuant to Public Utilities Code Section 311 and our Rules of Practice and Procedure, the ALJ's Proposed Decision was published on April 19, 1991; parties thereafter had an opportunity to file comments and reply comments.[63] We have considered the comments and have changed or clarified the Proposed Decision in various ways. All of the principles of the Proposed Decision are affirmed, but we have adopted several suggestions that will make implementation of those principles easier or more precise.[64] We address certain additional points below.

Some of the utility commenters object to the discussion of the "transmission bottleneck" (Section III.A) on the grounds that transmission issues were relegated to I.90-09-050. This is inaccurate. Utility proposals regarding line losses and interconnection costs were properly deferred to I.90-09-050, but the discussion in Section III.A deals, not with those proposals, but with competition. Moreover, the discussion responds to utility advocacy of all-source bidding, an issue which the assigned ALJ ruled (over QF objections) was germane to this phase of the BRPU. The relevance of transmission to competition in electric generation is well-established and has been exhaustively reviewed by this Commission as recently as its decision on the proposed merger between SDG&E and Edison. (See generally D.91-05-028 [122 PUR4th 225 (1991)].)

We emphasize that our remarks in Section III.A go to the nature of bottleneck facilities in general. We do not find, nor should any inference be drawn, that any of the respondents has made improper use of its transmission facilities.

TURN expresses concern that the rate impacts of today's decision, especially the treatment of residual emissions, are not quantified. We think TURN is premature. The rate impacts must be quantified in the context of utility resource plans. These will be filed in the next phase of the Update.

In the meantime, we have many qualitative assurances that we are doing the right thing for ratepayers. We start with an optimal utility strategy for meeting energy and air quality needs. We arrive at that strategy by considering uncertainty and strategic preferences. Timing will be an issue (e.g., are we spending too much too soon?) We then go through an acquisition process designed to secure for ratepayers equivalent benefits at a cost that is likely to be lower than what the utility would have to spend to provide those benefits on its own.

All parties must recognize, however, that internalizing environmental costs will have a rate impact. Many things will be necessary to minimize that impact, most importantly, coordination between the utilities, the CPUC, the CEC, and the air quality regulators.

Many commenters have asked that we expand on the proposed decision's discussion of workshops. We note, first, that the workshops are technical in nature; they are not for the purpose of creating policy but instead serve to translate our policies, set forth in today's decision, into the technical terms necessary to implement those policies through the final Standard Offer 4 contract and bidding protocol.

Second, we have for the most part declined to go into detail on what contractual terms must be developed to implement today's decision. While we think our policy discussion is clear, the parties undoubtedly have greater technical expertise, which is why we are holding workshops in the first place. Should disagreements develop over what our policy requires, the workshop participants can present consensus views where consensus is reached, and propose alternative resolutions where disagreements remain. We can then review these results for consistency with today's decision.[65] At the prehearing conference (see Section XV above), the assigned ALJ should solicit the parties' suggestions for the timing and conduct of the workshops.

Findings of Fact

1. Growth in QF capacity in California has occurred in part because utilities are now legally required to interconnect with QFs and to buy their output under terms and conditions supervised by this Commission.

2. Much of the utilities' market power in relation to QFs comes from utilities' control over transmission.

3. For the foreseeable future, the transmission sector of the electric industry will remain a natural monopoly.

4. Wheeling of QF power is an effective means of promoting competition in electric generation. Competitive markets have many buyers, many sellers, and ready access between the two.

5. By quantifying the value of fuel diversity and environmental quality, the CPUC can expand the ways in which different resource options compete and can increase the likelihood that the chosen options, all things considered, provide the greatest value to ratepayers.

6. We need to improve the way we account for the value of DSM to ensure a fully competitive resource procurement process.

7. For supply options, both the CPUC and the CEC use ICEM; for DSM, both agencies use the Standard Practice Manual for the Economic Analysis of Demand-Side Management Programs. The differing methods for quantitative analysis thwart efforts to directly compare supply options with DSM.

8. We are committed to head-to-head comparison of DSM and supply options in the planning process.

9. All-source bidding is a necessary component of a fully competitive resource procurement process, but we are not yet ready for all-source bidding. First, opening the auction to non-QF entities irrespective of the market power such entities may have will weaken competition, not increase it. Second, the QF category has not outlived its usefulness.

10. The electricity market structure has not yet changed so that future QF projects have assurance that they can compete fairly.

11. CPUC policy allows competition by all technologies, without setting aside any given amount of capacity for non-fossil technologies to further environmental or fuel diversity goals.

12. The impact of new electric resources on water and land use should be addressed in future Updates and Electricity Reports.

13. The value of fuel diversity depends on assessing the financial risks of relying too much on a given fuel, and on calculating how best to insure against those risks.

14. The producers (including utilities) that create pollution have generally not had to bear all the costs of pollution but have instead "externalized" a substantial part of those costs to society as a whole. The utilities logically should bear their fair share of such costs.

15. Acquiring "fuel diversity" for California utilities means increasing the proportion in their resource mix of electricity generated by plants that do not rely on oil, coal, or natural gas as their primary fuel source. Some technologies burn small amounts of natural gas, e.g., gas-assisted solar. A power plant using such a technology would still be considered non-fossil if it uses natural gas for no more than 25% of its total energy input during a calendar year.

16. Analysis of air quality impacts has been spurred by recent state and federal clean air legislation and actions by local air management districts. California utilities, along with other major sources of air pollutants, are facing major clean-up costs now or in the near future. Air basins in California must now achieve annual reductions in total emissions of specified air pollutants, and this will inevitably affect how each electric utility plans and operates its system.

17. Concentrations of criteria pollutants in excess of AAQS are unhealthy. When the concentration of a given criteria pollutant in an air basin regularly violates AAQS, the air basin is designated a non-attainment area. PG&E, SDG&E, and Edison all serve major metropolitan areas that are also non-attainment areas.

18. Many pollutants are produced when fossil fuels are burned. In particular, burning oil and gas will produce NOx. The CEC notes that in its ICEM analysis, NOx was the only pollutant whose value actually affected the timing of new resources, and NOx accounted for almost half the total value attributed to residual emissions.

19. Air quality (and the lack of it) has measurable impacts on productivity at work, enjoyment of leisure, and the length of life spans.

20. Electric generation serving California continues to be fueled primarily by oil, natural

gas, and coal.

21. A resource plan is a "least cost" plan if (among other things) it results in reasonable costs under the most likely future case and does not result in unduly high costs under alternative cases with a significant likelihood of occurrence. Fossil fuels are currently cheap and plentiful, but there is short- and long-term risk in assuming that they will continue to be so.

22. Developing resources that rely on alternative and renewable fuels will (1) cushion the impact of price shocks in fossil fuel markets, (2) help to avoid such shocks by lowering demand and extending current supplies of fossil fuels, and (3) improve the efficiency and cost-competitiveness of non-fossil technologies.

23. Assigning monetary values seems the best way to begin analyzing how environmental quality and fuel diversity should figure in the planning and acquisition of electric resources.

24. Using a fuel diversity premium instead of set-asides in acquiring non-fossil generation enables a better accounting for the benefits and costs of non-fossil generation than does set-asides.

25. This process (using a fuel diversity premium instead of set-asides) differs from ER-90's, but the purpose is identical and the result should be substantially the same, namely, filling the generation portion of need with a mix of fossil and non-fossil resources not exceeding the total MW of new generation found needed for each respondent utility in ER-90.

26. Where a utility's service area overlaps several air basins, values for residual emissions should come from the most significant air management district for that service area.

27. The air quality adder (subtractor) is an adjustment to the QF's energy payment and is separately computed for each pollutant by comparing the QF's emission rate to the IDR's.

28. Society cannot reasonably expect to get the clean air that society values without offering to pay for it. In fact, offering to pay will stimulate the competition that should ultimately drive down the cost of clean air.

29. If we value emissions for in-state projects but not for out-of-state projects, we confer an enormous competitive advantage on the latter for no reason other than that they foul someone else's air. But a policy of "exporting" pollution would not work if other states were to adopt a similar policy, and it would not work in any case because pollution, once emitted, does not respect state lines.

30. If more clean generation is added to an interconnected utility system, the utility can reduce its reliance on its dirtier plants.

31. A set-aside, compared to a single bidding arena for all technology types, will increase the cost to ratepayers of acquiring non-fossil resources.

32. Non-fossil QFs will have a substantial, value-based advantage in any auction using a fuel diversity premium.

33. Investment theory has reached a point where the value of diversification ought to be calculable, and it ought to be incorporated into any kind of least cost resource planning, whether from the traditional or social perspective.

34. The utilities have minimal experience with building non-fossil generation. The QFs themselves should be a better source for the capital costs of non-fossil and renewable technologies.

35. A cogenerator that cleans up 120% of its emissions is cleaner, from a social perspective, than a non-fossil plant with zero emissions.

36. As the cheaper offsets are bought up and offset sellers become better informed, the price of offsets should rapidly approach the buyer's marginal cost of emission control.

37. The prescribed 15-year term now in final Standard Offer 4 is not likely to be a good deal for ratepayers. Diversity is jeopardized by a limitation on contract length that puts non-fossil and renewable QFs at a disadvantage.

38. The utility may be considering 10-15 year plant life extensions that involve energy-related capital costs or power purchases of such length with a high level of fixed costs. There may be QFs interested in deferring IDRs with such shorter lives, and we want to explore this, at least until experience demonstrates a low-end threshold for Period 2.

39. Levelization represents far less front-loading than we allow utilities in their recovery of capital investments.

40. The CEC's latest findings on potential

IDRs suggest that the difficulty in financing capital-intensive QFs will be greater than we anticipated when we chose to totally exclude front-loading from final Standard Offer 4.

41. QFs have not demonstrated that their financing requires levelization of anything besides shortage costs.

42. Different power plants have different cost streams. Some have high fixed and low variable costs, while others have low fixed and high variable costs. The latter category includes plants that chiefly rely on oil or gas; all other plants fall into the former category.

43. The current auction requires all QFs to bid a capacity price expressed as a percentage of the capital costs of the IDR. For non-fossil QFs, all other costs are recovered through variable payments equal to the variable costs of the IDR. This puts capital-intensive QFs at a disadvantage, relative to oil/gas-fired QFs, when bidding on an IDR, such as a combined cycle, with a low fixed and high variable cost structure.

44. California utilities remain highly dependent on oil/gas-fired resources.

45. Bidding energy and capacity has many advantages. First, it permits all types of QFs to bid a payment structure appropriate to their technology. The current bidding system favors QFs whose cost structure is similar to that of the IDR. Second, such bidding shields ratepayers from undue fuel price risks. Third, having a more accurate picture of the QF's energy cost means that utilities can dispatch the system more efficiently.

46. Linking variable cost payments to a QF's own cost stream should enable the purchasing utility to make more efficient curtailment decisions and should make QFs indifferent to such decisions. In particular, those QFs (e.g., solar) whose fuel source makes it hard for them to curtail should benefit since their low variable costs will virtually eliminate the possibility of economic curtailment.

47. The uniform pricing in a second-price auction conforms much more closely to the market-clearing price of a competitive market than does discriminative pricing in a first-price auction.

48. The bidder in a second-price auction has a strong incentive to bid a price reflecting its true marginal cost. The result is that the second-price auction reveals bidders' relative costs quite accurately and awards contracts to the low-cost bidders.

49. The bidder in a first-price auction has a strong incentive to bid *more* than its marginal cost. Thus, under a first-price auction, bids are *higher* than under a second-price auction. Also, the first-price auction doesn't necessarily award contracts to low-cost bidders, but rather to bidders who are good at guessing how much to inflate their bids and still win.

50. California policy-makers are sensitive to the problem of regulatory costs. The CEC, which provides one-stop siting for major thermal power plants, was created in part to reduce or eliminate such costs; the Permit Streamlining Act is another legislative response to the problem. Our joint effort with the CEC to coordinate QF procurement with the CEC's integrated assessment of need is similarly motivated.

51. In the BRPU we are trying to internalize pollution costs in the resource procurement process. This is similar to the rate design principle that the person causing specific costs should bear them. This principle is entirely consistent with a market-oriented philosophy of regulation.

52. Regulatory costs are real costs that we fold into our resource procurement process. The IDR's estimates include estimated costs for permitting and environmental mitigation. Those estimates are known to the bidder in advance, and the bidder can make its own judgment of siting risks compared to those of the IDR.

53. The second-price auction is the logical extension of full avoided cost, with the lowest losing QF replacing the IDR as the price benchmark whenever QFs offer more capacity than the utility seeks.

54. Our resource procurement process is sufficiently flexible to consider differential impacts of various resource options on such things as transmission costs, environmental quality, and fuel diversity. All that is necessary is that the QF know before bidding what costs it will be expected to bear and how the benefits that it offers the ratepayer will be paid for by the utility.

55. Exact estimates of IDR costs are criti-

cal, but the ER/BRPU cycle contains safeguards that may be adequate to ensure the credibility of the IDR benchmark.

56. We may be able to limit controversy in future Updates by establishing a set of check points to link specific modifications to final Standard Offer 4 with specific achievements in providing transmission-only service and evaluating non-price factors.

57. It should be to California utilities' advantage to use QFs to prompt better terms from non-QF sellers.

58. The ER/BRPU process preserves a niche for QFs and DSM without disabling the utilities from pursuing the universe of resource options.

59. Uncommitted DSM consists of programs that are not currently in place but that the CEC expects to receive regulatory approval during the forecast period.

60. This Commission's ultimate goal is direct competition among all generation options. Eventually, generation and DSM may also compete directly, and the basis for reserving some portion of need for particular resource categories may vanish. Until then, regulators must ensure that traditional utility resources still retaining market power do not displace cleaner, smaller, more efficient alternatives.

61. We propose the following procedure for switching QFs and invite comment on the procedure in the new phase of the Update. Switching QFs would submit an energy price under seal. After the utility announces the auction result, switching QFs that choose to exercise their right would tell the utility to unseal their submitted energy prices and compute a capacity price using the same calculation methods applicable to winning QFs. A QF that chooses not to switch after the announcement would so notify the utility, which would immediately return the QF's energy price submittal *unopened*. If a QF that submitted an energy price fails, within 30 days of notification by the utility of the auction result, to notify the utility of its decision whether to switch, it would lose its right to switch for purposes of that auction only, and the utility would return the unopened energy price submittal.

62. Lower running costs are a major element of an IDR's cost-effectiveness. Payments to QFs receiving short-run marginal cost-based energy payments are a major element of a utility's running costs. However, Standard Offer 1 QFs are a small fraction of the QFs receiving such energy payments, and there is no reason to think that all Standard Offer 1 QFs would be successful bidders, to the exclusion of all other bidders in a given auction, even assuming that they could satisfy the substantially more arduous performance requirements of final Standard Offer 4.

63. The participation of Standard Offer 1 QFs in the second-price auction could result in a lower price to all successful bidders.

64. The BRPU is not suited to determining the value to ratepayers of demonstration projects in general or of particular demonstration projects.

65. Our past decisions on nonstandard contracts and on utility/QF negotiations give adequate guidance for QF demonstration project sponsors at this time.

66. Our experience with long-run standard offers teaches that uncertainty should be dealt with explicitly in the planning process, that known risks should be quantified, and that strategic elements should be built into the resource plan to respond to those risks.

67. We do not intend, under the rubric of uncertainty analysis, to undermine the ER-90 forecasts or somehow compensate for perceived deficiencies in the ER process.

68. For several agencies to perform somewhat overlapping analyses is not a planning failure, it is inevitable in something with as many complex ratifications as electricity resource planning. Resource planning can be no one agency's exclusive domain.

69. Standard Offer 2 is a short-run offer in that it uses short-run principles to determine energy and capacity prices, but it has some important characteristics of a long-run offer.

70. Standard Offer 2 suffers from the same deficiency as interim Standard Offer 4 in not being clearly tied to a determination of deferrable MW. Also, although Standard Offer 2 is a long-term commitment by the utility and QF, energy payments are tied to the purchasing utility's short-run marginal cost. This increases

the ratepayer's exposure to rising oil and gas prices even if the QF is not oil/gas-fired.

71. If final Standard Offer 4 works as intended, even a limited reinstatement of Standard Offer 2 should be unnecessary. Should we decide to reinstate Standard Offer 2 for whatever reason, we expect that the reinstatement would be limited as it was for SDG&E. Also, the fuel price risk should be mitigated by appropriate indexing of the energy payment if the QF is not oil/gas-fired. Finally, the queue management rules should be improved to resolve oversubscription.

72. Waste-to-energy QFs promise both energy and environmental benefits. However, they use a capital-intensive technology that our experience shows has a long and uncertain lead time. A nonstandard power purchase agreement drawing many of its provisions from Standard Offer 2 may prove to be the most appropriate contractual vehicle for such QFs. Our past decisions on nonstandard contracts should guide the utility and QF in negotiating such contracts.

73. Energy bidding may require certain changes to existing curtailment provisions of final Standard Offer 4 so that these provisions are consistent with the policy basis for energy bidding.

Conclusions of Law

1. The category of non-utility power producers known as QFs was developed to implement PURPA and includes various restrictions and requirements furthering the statutory intent.

2. ICEM should reflect the "residual emissions" (those remaining after application of appropriate control technology) associated with the operation of any resource being tested for cost-effectiveness. The (negative) value of such emissions should be determined using the principle of "revealed preference," which means that the costs imposed by relevant regulatory agencies, for example, in requiring certain pollution abatement actions, will be analyzed to calculate the implicit monetary value assigned to avoiding a given quantity of a given pollutant.

3. Residual emissions should figure throughout the procurement process, that is, in both the planning and the acquisition of new resources.

4. If any "offsets" are associated with the deferrable or bid resource, the impact of such offsets should also be included in the procurement process.

5. Some non-fossil IDRs, because they are generally "clean" technologies, are likely to appear simply through inclusion in ICEM of residual emissions. Should that not occur, the utilities should impute additional value to non-fossil resources until non-fossil candidate resources appear as the first addition during the next eight years in their resource plans. This will effectively quantify the size of any premium necessary to secure non-fossil resources. We will decide in the new Update phase whether any such premium is reasonable.

6. Air management districts have the ability to require retrofits of power plants. Also, air management districts may require new sources to apply BACT.

7. New sources may also have to acquire "offsets" of any residual emissions after application of BACT. Air management districts in non-attainment areas may require such offsets in a ratio greater than one-to-one.

8. While electric generation is not the primary source of criteria pollutants, it is a major contributor. Its emissions impose costs on society that should be accounted for.

9. To determine just and reasonable rates, this Commission must know how resource procurement decisions will affect rates.

10. The air management districts are responsible for developing programs to meet air quality goals, and the districts are best situated to determine values for the costs and benefits of those programs.

11. SCAQMD's recommended values for residual emissions shall be used by Edison in performing ICEM analysis and shall be applied in calculating adders (subtractors) for auction winners.

12. The San Diego APCD has proposed rules similar to SCAQMD's or even stricter. Pending final action by the San Diego APCD, the SCAQMD values are the best available for San Diego.

13. ER-90 projects $13 per kilowatt (1987

dollars) as the cost to PG&E of retrofitting its plants for NOx control. PG&E's compliance report in the next Update phase should convert this cost to a dollars per ton figure, and should explain how PG&E calculated the conversion. Alternatively, PG&E may use 29% of the SCAQMD value for NOx. Values for ROG should come from ER-90 (in-state) and other residual emissions on the PG&E system should come from the Pace University Study.

14. The emissions values adopted today are interim values. They should be revised in subsequent Updates to reflect emerging abatement requirements of the relevant air management districts.

15. An interim value for carbon emissions is prudent. The utilities should apply the value adopted in ER-90 ($26/ton in 1987 dollars) for carbon emissions. This value will be used in the same ways as the values for other residual emissions.

16. The environmental costs of electricity generated from sources outside California or outside the service area of the utility acquiring that electricity should be calculated the same as if the electricity were generated within the utility's service area.

17. For the next Update phase, each utility will perform ICEM analysis using values for residual emissions. If a non-fossil IDR appears in the "deferral window" (through 1999), a fuel diversity premium will not be calculated. If a non-fossil IDR does not appear, the utility will calculate a value for fuel diversity sufficient to have a non-fossil candidate resource appear as the earliest IDR in the deferral window. In making this calculation, the utility will follow the approach described in Section IV.E.4 of today's decision.

18. A QF that does not provide "fuel diversity" would not get the fuel diversity premium.

19. The term of Period 2 in final Standard Offer 4 should be up to the full projected life of the IDR. This term will be available to all QFs, irrespective of their technology. The term may be less, at the QF's election, but must be at least 15 years (if the projected life of the IDR is 15 years or more) or the life of the IDR (if its projected life is less than 15 years).

20. Levelized shortage costs together with appropriate security provisions are reasonable for final Standard Offer 4. A final Standard Offer 4 QF may choose either a ramped payment stream or a partially levelized payment stream.

21. Levelization will be available to all QFs, irrespective of their technology. This is consistent with other changes in today's decision designed to achieve as far as possible uniform treatment of all QFs.

22. The IDR should remain the benchmark for QF bidding, but avoided cost principles do not require QFs to match the IDR payment structure. Both capital-intensive QFs and cogenerators should benefit from bidding a payment structure that corresponds to the cost structure of the plant to be financed.

23. Before the auction, the utility should publish all pertinent physical and cost characteristics of the IDR. These include economic life, capacity factor and hours of operation, shortage and other capital costs (and allocation factors for those costs), fuel type(s), residual emission rates, offsets, operation and maintenance costs, first year fuel price, heat rate, assumed fuel price escalator, GNP deflator, and all other projections or assumptions specific to the IDR used in calculating its cost-effectiveness. Using these characteristics and an explicit methodology, the utility will combine the stream of projected fixed and variable costs into a single first-year cost expressed in cents per kilowatt hour. This number will be the IDR benchmark.

24. Bidding QFs should analyze their own cost characteristics compared to the IDR. They will submit a sealed bid for a stated effective capacity and separately stated variable (energy) and fixed (capacity) prices. The QFs will know that the utility will recombine their energy and capacity price into a single cents per kilowatt hour first-year cost, using the some methodology used to calculate the IDR benchmark. They will also know that the winning bidders will be chosen under second-price rules by comparing each bidder's and the IDR's projected first-year cost. Finally, they will know what environmental adders/subtractors (and fuel diversity premium, if any) they will receive if they win.

25. Once the winning bidders are chosen,

variable payments will be based on the bidder's energy price plus any environmental adders/subtractors. Escalation will depend on the fuel type of the QF. Variable payments to non-fossil and renewable QFs will escalate with GNP. Variable payments to other QFs will escalate based on the same fuel index and price update schedule already adopted for final Standard Offer 4.

26. Capacity payments will be determined by subtracting the energy bid by the winning QF (or the converted energy price, where the QF's energy bid was converted to get a common escalation basis) from the *total* first-year cost of the lowest losing bid. The remaining cents per kilowatt hour will be converted to dollars per kilowatt fixed payments, will be divided between shortage and other capital costs, and will be paid, as already adopted, on a time-differentiated basis.

27. The principles supporting our adoption of full avoided cost pricing for QFs also apply to our choice of auction format. The second-price auction serves our policies in the QF program and should be retained.

28. The new phase of BRPU should include consideration of proposals to keep QF bids confidential even after they are opened. The purpose of such confidential treatment would be to further the cost-revealing properties of the second-price auction by guarding possibly market-sensitive information.

29. The utility has the burden of noting any inconsistency between resource assumptions it uses in the BRPU and those it uses in other proceedings. The utility must also explain and justify such inconsistencies in these other proceedings.

30. The utility is not "committed" to build the deferrable resource as of the date it is identified.

31. Reasonableness review and cost caps developed pursuant to Public Utilities Code § 1005.5 provide protection against cost overruns on utility construction projects. If experience shows that cost estimates in the BRPU are unrealistic, we may reconsider the question of whether and how to hold the utility to the benchmark price.

32. Currently, only QFs may bid in the final Standard Offer 4 auction. We will retain this limitation for the time being, but we intend to move toward "all-source" bidding. This move depends on making significant progress in evaluating non-price factors and in allowing nondiscriminatory access to electric transmission services ("wheeling") for nonutility power producers. Absent these conditions, the results of all-source bidding would be renewed reliance on traditional supply options.

33. When we again take up the subject of expanding the kinds of entities that may bid, we expect the proponents of such expansion also to take the initiative in proposing appropriate regulations to ensure that self-dealing does not subvert the goal of enhanced competition.

34. Utilities may negotiate power purchase agreements at any time, but they may not modify a long-run standard offer during the three-month solicitation period. A utility considering a resource opportunity during the solicitation period must consider whether the opportunity is still attractive assuming full subscription of the solicitation at various price levels at or less than the IDR benchmark.

35. GRA/IEP may bring up in Phase 3 of this proceeding their proposal for a capacity payment floor for a utility's as-available QFs based on short-term power purchases made by that utility between Updates.

36. The fundamental purpose of the BRPU is to implement a long-run standard offer at a level of potential commitment to QFs that both this Commission and the CEC believe is consistent with the need for electricity in California. Such implementation requires us to make a coordinated review of the resource plans of the major investor-owned electric utilities. The integrity of this process also requires that utility actions taken between the coordinated review be consistent with the assumptions and policies that form the basis of the utilities' resource plans. Thus, the utilities must either use the same assumptions or identify and justify, in whatever forum such utility actions are reviewed, any departure from those assumptions.

37. The reasonableness thresholds for power purchases proposed by PG&E, SDG&E, and DRA are unnecessary and undesirable.

38. Reasonableness review of power purchases should cover the timing of the utility commitment, including the issue of whether the price or other terms of the purchase were so good as to justify the utility's decision not to risk the lapse or withdrawal of the offer by treating it as an IDR in an Update.

39. The reasonableness of a utility decision depends on things known or reasonably knowable by the utility when the decision was made. Our long-run avoided cost projections made during the most recent BRPU should not be highly sensitive to short-term phenomena arising during the ER/BRPU cycle, but we nevertheless require the utility to act on power purchase opportunities based on the best currently available information.

40. QFs entitled to switch to final Standard Offer 4 do not count against the MW limits and are not required to bid. They are affected by the second-price auction only to the extent that, like the winning bidders, their price is set by the lowest losing bid. If they are dissatisfied with the price, they need not exercise their right to switch but can wait for later Updates.

41. In the future, parties proposing changes to final Standard Offer 4 must indicate how switching QFs would exercise that right under their proposals. We will not entertain any proposal that would require such QFs to submit competitive bids.

42. No environmental adder or subtractor should apply to payments under final Standard Offer 4 to a switching QF.

43. QFs currently under contract may bid, but only after they have fulfilled their obligations under their existing power purchase agreement. However, Standard Offer 1 QFs have few such obligations. They deliver "as-available" energy and capacity, and they are contractually entitled to terminate their power purchase agreement at any time without penalty. In effect, consistent with the eligibility rules, a Standard Offer 1 QF is free to bid in any auction and need only terminate its existing contract if it wins.

44. To the extent that Standard Offer 1 QFs are technically and otherwise able to provide firm energy and capacity, they should be encouraged to do so and should have access to appropriate contracts for firm power sales.

45. Standard Offer 1 QFs may participate in the final Standard Offer 4 auction, so long as such a QF provides new capacity, e.g., by expanding its plant or committing to firm operation. If that QF is successful in the auction, the purchasing utility should count the QF's capacity toward the MW limit, using the appropriate nameplate-to-effective capacity conversion factor when comparing the QF's system contribution under Standard Offer 1 and final Standard Offer 4.

46. Any demonstration project should not count against "need" for purposes of BRPU.

47. The potential under Texaco's cumulative allocation proposal for a huge number of MW in a single ER cycle is risky and inconsistent with the CEC's recommendation. Any such allocation of MW for demonstration projects should be non-cumulative.

48. The CPUC is charged with establishing just and reasonable utility rates.

49. Given the CPUC's obligation to ensure that utility rates are just and reasonable, the CPUC is also obliged to ensure that the resource plans on which final Standard Offer 4 solicitations are based incorporate appropriate hedging strategies.

50. The utility compliance reports in the next phase of the Update will reflect directions in this decision and in D.90-03-060 to the extent such directions differ from ER-90. We expect that these differences may affect the type and timing of IDRs and possibly suggest different hedging strategies. However, we also expect to meet our commitment to tailor the ensuing QF solicitation to ER-90's integrated assessment of need.

51. Final Standard Offer 4 should be our primary instrument for directly involving QFs in resource procurement. We do not rule out reinstating Standard Offer 2, provided that such reinstatement is accompanied by certain modifications, and is for a limited amount of time and capacity. Standard Offer 2 may also be useful as a model for some kinds of nonstandard contracts. We do not envision making Standard Offer 2 available on an ongoing basis.

52. The Assigned ALJs in this proceeding and in I.90-09-050 should promptly notice a joint prehearing conference to schedule and coordinate tasks in the two proceedings, consistent with the discussion in Section XV of the foregoing opinion.

53. The utility should not be permitted to bid against its own IDR. If the utility could do better than the IDR, ratepayers are entitled to have that superior resource used to set the benchmark price.

FINAL ORDER — PHASE 1B

IT IS ORDERED that:

1. The uniform final Standard Offer 4 power purchase agreement and auction protocol shall be modified to conform with the discussion, findings, and conclusions in this decision. The Assigned Administrative Law Judge shall convene workshops to develop these modifications.

2. The Assigned Administrative Law Judges shall notice a joint prehearing conference in this proceeding and in Investigation 90-09-050 to coordinate scheduling and priorities consistent with this opinion.

3. Nine weeks from the effective date of this order, respondents Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company shall file their compliance reports containing their resource plans following the 1990 Electricity Report and in conformity with this decision and Decision 90-03-060 (36 CPUC 2d 2 [1990]). The reports shall also contain respondents' latest work on integrating demand-side and supply-side resources on a common analytical basis.

This order is effective today.

Dated June 5, 1991, at San Francisco, California.

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ATTACHMENT 1

Table of Acronyms and Abbreviations

A.	Application
AAQS	Ambient Air Quality Standards
ALJ	Administrative Law Judge
BACT	Best Available Control Technology
B/C Ratio	Benefit/Cost Ratio (a measure of cost-effectiveness)
BRPU	Biennial Resource Plan Update
CEC	California Energy Commission
CEERT	Coalition for Energy Efficiency and Renewable Technologies
Chevron	Chevron U.S.A. Inc.
CPUC	California Public Utilities Commission
D.	Decision
DRA	Division of Ratepayer Advocates (Part of CPUC staff)
DSM	Demand-side Management
Edison	Southern California Edison Company
ER-90	1990 Electricity Report of the CEC
FERC	Federal Energy Regulatory Commission
GNP Deflator	A measure of overall price changes in the economy, equal to the ratio of gross national product (GNP) measured in current, or nominal, dollars to GNP measured in constant, or real, dollars.
GRA/IEP	Geothermal Resources Association and Independent Energy Producers Association
I.	Investigation

ICEM	Iterative Cost-effectiveness Methodology
IDR	Identified Deferrable Resource
IER	Incremental Energy Rate
MW	Megawatt
NO_x	Nitrogen/Oxygen Compounds
NRRI	National Regulatory Research Institute
PG&E	Pacific Gas and Electric Company
PM	Particulate Matter (suspended)
Powerex	British Columbia Power Exchange Corporation
PURPA	Public Utility Regulatory Policies Act
QF	Qualifying Facility
R.	Rulemaking
RD&D	Research, Development and Demonstration
ROG	Reactive Organic Gases
RT	Reporter's Transcript
San Diego APCD	San Diego Air Pollution Control District
SCAQMD	South Coast Air Quality Management District
SDG&E	San Diego Gas & Electric Company
SO_x	Sulfur/Oxygen Compounds
Texaco	Texaco Syngas Inc.
TURN	Toward Utility Rate Normalization
Update	Biennial Resource Plan Update

(END OF ATTACHMENT 1)

ATTACHMENT 2

Landmark CPUC Decisions on Avoided Cost, Standard Offers

The following list, although not exhaustive, shows where to find answers to the key questions that the Commission has addressed regarding QFs. The summaries are necessarily terse and are not intended either to indicate each issue in any given decision or to substitute for review of the actual text of the opinion and order. In addition to these decisions, our general rate case decisions have been used in the past to update certain standard offer terms. Finally, decisions in general rate case and fuel offset proceedings often contain analysis of marginal cost that is broadly relevant to QF policy.

I. *Foundational Decisions*

D.91109 — adopted "avoided cost" pricing for utility purchases from "private energy producers"

D.82-01-103 — guidelines for standard offers

D.82-04-071 — authorized "hydro savings prices" during spill conditions

D.85-07-022 (18 CPUC 2d 333, 68 PUR4th 1 [1985]) — long-run avoided cost methodology

II. *Decisions Implementing Variable Energy Payments and Standard Offers 1, 2, and 3 (the Short-run Offers)*

D.82-12-120
D.83-10-093 (13 CPUC 2d 84 [1983])
D.84-03-092 (14 CPUC 2d 489 [1984])
D.84-04-012 (14 CPUC 2d 563 [1984])
D.88-07-024 (28 CPUC 2d 511 [1988])
D.89-02-065 (31 CPUC 2d 115 [1989])

III. *Decisions on Interim Standard Offer 4 (the Interim Long-run Offer)*

D.83-09-054 (12 CPUC 2d 604 [1983])
D.83-12-050 (13 CPUC 2d 592 [1983])
D.84-08-035 (16 CPUC 2d 37 [1984])
D.84-10-098 (16 CPUC 2d 362 [1984])
D.85-01-040 (17 CPUC 2d 118 [1985])
D.85-02-069 (17 CPUC 2d 182 [1985])
D.85-04-075 (17 CPUC 2d 521 [1985])
D.85-06-163 (18 CPUC 2d 264 [1984])
D.85-07-121 (18 CPUC 2d 455 [1985])
D.86-10-038 (22 CPUC 2d 105 [1986])
D.86-12-013 (23 CPUC 2d 1 [1986])
D.86-12-104 (23 CPUC 2d 414 [1986])

IV. *Show Cause Proceeding (PG&E)*

D.84-03-093 (14 CPUC 2d 535) [1984]
D.84-08-031 (16 CPUC 2d 5 [1984]) — "good faith" guidelines for utilities in negotiating with QFs

V. *Investigation of Transmission Constraints, Development of QF Milestone Procedure, and Administration of Transmission Priority*

D.84-08-037 (16 CPUC 2d 38 [1984])
D.85-01-038 (17 CPUC 2d 87, 64 PUR4th 537 [1985])
D.85-01-039 (17 CPUC 2d 113 [1985])
D.85-08-045 (18 CPUC 2d 576 [1985])
D.85-09-058 (19 CPUC 2d 15 [1985])
D.85-11-017 (19 CPUC 2d 149 [1985])
D.85-12-075 (19 CPUC 2d 435 [1985])
D.86-02-033 (20 CPUC 2d 486 [1986])
D.86-04-053 (21 CPUC 2d 53 [1986])
D.86-11-005 (22 CPUC 2d 293 [1986])
D.86-12-017 (23 CPUC 2d 3 [1986])
D.87-04-039 (24 CPUC 2d 144 [1987])
D.87-08-028 (25 CPUC 2d 176 [1987])
D.87-09-030 (25 CPUC 2d 371 [1987])
D.88-04-067 (28 CPUC 2d 101 [1988])
D.89-01-044 (30 CPUC 2d 677 [1989])
D.89-07-058 (32 CPUC 2d 313 [1989])

VI. *Standard Offer 2: Suspension and Reinstatement*

D.86-03-069 (20 CPUC 2d 644 [1986])
D.86-05-024 (21 CPUC 2d 124 [1986])
D.86-11-071 (22 CPUC 2d 311 [1986])
D.87-09-025 (25 CPUC 2d 298 [1987])
D.87-11-024 (26 CPUC 2d 62 [1987])
D.87-12-056 (26 CPUC 2d 340 [1987])
D.89-02-017 (31 CPUC 2d 13 [1989])
D.89-07-022 (32 CPUC 2d 284 [1989])
D.89-08-031 (32 CPUC 2d 371 [1989])

VII. *Development of the Resource Plan-based Offer (Final Standard Offer 4)*

D.85-07-022 (68 PUR4th 1 [1985])
D.86-07-004 (21 CPUC 2d 340, 76 PUR4th 1 [1986])
D.86-10-030 (22 CPUC 2d 99 [1986])
D.87-05-060 (24 CPUC 2d 253 [1987])
D.87-11-024 (26 CPUC 2d 62 [1987])
D.88-03-026 (27 CPUC 2d 502 [1988])
D.88-03-079 (27 CPUC 2d 559, 91 PUR4th 143 [1988])
D.88-09-026 (29 CPUC 2d 263 [1988])
D.89-04-047 (31 CPUC 2d 458 [1989]) (Curtailment)
D.89-07-045 (32 CPUC 2d 294 [1989])
D.90-03-060 (36 CPUC 2d 2 [1990])

VIII. *"Orphans," "Pioneers," and Nonstandard Contracts*

D.93035
D.93364
D.82-04-087
D.82-07-021
D.83-05-043 (11 CPUC 2d 490 [1983])
D.83-05-047 (11 CPUC 2d 493 [1983])
D.83-06-109 (11 CPUC 2d 1034 [1983])
D.84-05-057 (15 CPUC 2d 110 [1984])
D.86-03-030 (20 CPUC 2d 625 [1986])
D.86-06-060 (21 CPUC 2d 287 [1986])
D.86-07-032 (21 CPUC 2d 405 [1986])
D.86-08-017 (21 CPUC 2d 471 [1986])
D.86-09-040 (22 CPUC 2d 40 [1986])
D.86-10-039 (22 CPUC 2d 113 [1986])
D.86-10-044 (22 CPUC 2d 114 [1986])
D.86-12-018 (23 CPUC 2d 4 [1986])
D.86-12-061 (23 CPUC 2d 55 [1986])
D.86-12-062 (23 CPUC 2d 65 [1986])
D.86-12-098 (23 CPUC 2d 315 [1986])
D.86-12-100 (23 CPUC 2d 348 [1986])
D.87-01-049 (23 CPUC 2d 499 [1987])
D.87-03-068 (24 CPUC 2d 64 [1987])
D.87-05-065 (24 CPUC 2d 367 [1987])
D.87-07-086 (25 CPUC 2d 76 [1987])
D.87-08-047 (25 CPUC 2d 179 [1987])
D.87-09-074 (25 CPUC 2d 421 [1987])
D.87-09-080 (25 CPUC 2d 435 [1987])
D.87-10-038 (25 CPUC 2d 463 [1987])
D.87-11-063 (26 CPUC 2d 112 [1987])
D.88-03-036 (27 CPUC 2d 525 [1988])

IX. *Energy Reliability Index (ERI) Capacity Valuation Methods*

D.86-11-071 (22 CPUC 2d 311 [1986])
D.88-03-079 (27 CPUC 2d 559, 91 PUR4th 143 [1988])
D.89-06-048 (32 CPUC 2d 177 [1989])

X. *Out-of-Service Area QFs*

D.88-04-070 (28 CPUC 2d 138 [1988])
D.88-09-067 (29 CPUC 2d 405 [1988])

XI. *Avoidable Gas Costs*

D.88-07-024 (28 CPUC 2d 511 [1988])
D.89-09-099 (32 CPUC 2d 514 [1989])
D.90-12-028

XII. *Contract Administration*

D.88-10-032 (29 CPUC 2d 415 [1988]) in R.88-06-007 (Guidelines)

(END OF ATTACHMENT 2)

ATTACHMENT 3

Summary of Standard Offers[1]

STANDARD OFFER 1: Variable Capacity and Energy

The QF's energy and capacity are sold on an as-available basis, meaning that the amount and time of delivery of the energy is not guaranteed. The QF is paid full short-run avoided energy cost, plus current shortage cost, on a per kilowatt-hour basis, for all energy delivered to the utility. Energy and shortage costs are updated quarterly and annually (respectively), with the energy cost based on the incremental energy rates established in the utility's last fuel offset proceeding and the expected fuel costs for that quarter. Shortage costs are based on the utility's cost of a combustion turbine. This contract is used by all technologies, but particularly wind, due to the uncertain nature of that resource.

STANDARD OFFER 2: Firm Capacity and Variable Energy

The QF's capacity is sold on a firm basis, meaning that an amount of capacity is guaranteed to be available to the utility during its peak load period. The capacity payments are based on levelized, forecasted shortage costs, which are stated in the contract and are fixed for the life of the contract. Energy prices are the same as in Standard Offer 1. Many cogenerators and biomass QFs hold Standard Offer 2 contracts.

STANDARD OFFER 3: Variable Capacity and Energy From QFs Not More Than 100 Kilowatts

This offer is the same as Standard Offer 1 in practice, but the contract terms and QF responsibilities are less involved, due to the small size of the facilities.

INTERIM STANDARD OFFER 4: Long-term Capacity and Energy, Based on Forecast of Short-run Marginal Cost

This offer has fixed payment rates over long time spans (up to 10 years). There are three energy payment options and two capacity options.

Energy Option 1) Energy prices are fixed and are based on forecasted avoided energy costs. The QF can choose to have a mix of forecasted and current short-run avoided costs for the energy price, with oil & gas-fired cogenerators limited to 20% of the price being based on the forecasted prices.

Energy Option 2) This is similar to Option 1, except that the forecasted energy prices are levelized and oil & gas-fired cogenerators may not use this option at all.

Energy Option 3) Energy prices are based on fixed, forecasted utility incremental energy rates and utility oil & gas costs. Payments are made based on short-run costs, then adjusted at the end of the year to reflect the forecasted prices. This option is used by cogenerators and is designed to have the energy price reflect changes in fuel costs.

Capacity Option 1) As-available: The QF can choose payments based on either short-run shortage costs, or fixed, forecasted shortage

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costs, which are not levelized.

Capacity Option 2) Firm: Payments are based on fixed, forecasted, levelized shortage costs.

FINAL STANDARD OFFER 4: Long-term Capacity and Energy, Based on Avoidable Resource

See Attachment 3.

(END OF ATTACHMENT 3)

ATTACHMENT 4

How Final Standard Offer 4 Works[1]

Unlike the short-run standard offers and the interim long-run standard offer, final Standard Offer 4 derives from the respective utility's resource plan (including potential new plant construction, refurbishments, power purchases, etc.), as reviewed by the Commission in a biennial update proceeding. Pricing under final Standard Offer 4 varies according to when the QF comes on-line. During Period 2, the QF avoids a specific utility generation resource, and the QF receives payments based on the fixed and variable costs of the avoided resource. If the QF comes on-line in Period 1, i.e., before the date when the avoided resource would have begun delivery of electricity, the QF meets near-term demand growth, and therefore the QF receives short-run marginal cost-based payments until the start of Period 2. The Commission considers uncertainties and procurement strategies for each utility in determining a megawatt (MW) limit at each update proceeding. Whenever the capacity of QFs seeking final Standard Offer 4 contracts from a given utility exceeds that utility's MW limit, the available contracts are allocated through bidding. The utilities are also authorized to pay QFs additional sums for providing performance features (e.g., downward dispatchability at the utility's direction) not otherwise required under the standard offers.

We have adapted the following chronological overview from prior orders. We think the details of the final Standard Offer 4 resource planning process are more easily grasped with the total design in mind.

Step 1: *The utility application.* Following the latest Electricity Report of the California Energy Commission (CEC), the Pacific Gas and Electric Company, the San Diego Gas & Electric Company, and the Southern California Edison Company each file a resource plan with a 12-year planning horizon. The plan identifies within the horizon those potential resource additions that the applicant believes are cost-effective for its system. The plan states the costs associated with each such resource and the point in the planning horizon when that resource becomes cost-effective. The plan also states all relevant assumptions. The applicant presents its assumptions in internally consistent "scenarios." The latest CEC Electricity Report forecasts give the supply and demand assumptions for the base case scenario. The applicant may also file additional scenarios, or otherwise deal with the range of uncertainties underlying the forecasts, in order to explain the applicant's preferred procurement strategy.

Step 2: *Hearings on the utility applications.* The Commission's staff and other participants critique each resource plan. They may note internal inconsistencies in any of the applicants' scenarios, present alternative scenarios of their own, criticize the applicant's assessment of uncertainty, and challenge the reasonableness of an applicant's assumptions. They also check that the applicants have correctly implemented the Commission's cost-effectiveness methodology. Finally, these participants may explain their choice of the scenario best suited to the determination of avoidable plants.

Step 3: *Commission determination of avoidable plants for the respective utilities.* Avoidable plants are essentially the cost-effective baseload or intermediate resource additions appearing in the first eight years of the resource plan that is preferred by the Commission. This choice is the key Commission act in the long-run standard offer process. The Commission makes this choice according to the following criteria, among others: Are the plan and underlying assumptions plausible (i.e., internally consistent and reasonable, given known forecast uncertainties)? Does the plan expose ratepayers to unnecessary risks, either of premature commitments or of shortages? Is the plan consistent with energy regulatory goals and policies? The Commission decision comes about five months after filing of the applications.

Step 4: *The utilities' solicitation process and QF auction.* After making any modifications ordered by the Commission, the utilities announce the availability of long-run standard offer contracts based on the capacity and the fixed and variable costs of the avoidable resource(s). QFs have a three-month solicitation period to respond. Each interested QF indicates (1) the resource that the QF seeks to avoid, (2) the QF's own technology and capacity, and (3) the QF's bid, which is the lowest percentage of the resource's fixed costs that the QF would be willing to accept. The bid cannot exceed the resource's fixed costs. The utility opens the responses at the end of the solicitation period. If QFs seeking to avoid a resource do not cumulatively exceed the resource's capacity, all these QFs are offered contracts at the full fixed costs of the resource. If such QFs do exceed the resource's capacity, contracts up to that MW limit are offered to the low-bidding QFs, and they receive that percentage of the resource's fixed costs bid by the lowest *losing* bidder. (This is known as a "second price" auction.) Contract signing occurs after the winning bidder complies with the prerequisites of the QF Milestone Procedure, roughly one year after the utility applications.

Step 5: *Update to the long-run standard offer.* The update is scheduled every two years and follows each CEC Electricity Report. The utilities file new resource plans, and Steps 1 through 4 are repeated, with such modifications to the process as the parties may suggest and the Commission approves.

(END OF ATTACHMENT 4)

ATTACHMENT 5

Public Utilities Code Section 701.1
Added by Assembly Bill 3995 (Sher),
in Stats. 1990, Ch. 1475, Sec. 2

701.1 (a) The Legislature finds and declares that, in addition to other ratepayer protection objectives, a principal goal of electric and natural gas utilities' resource planning and investment shall be to minimize the cost to society of the reliable energy services that are provided by natural gas and electricity, and to improve the environment and to encourage the diversity of energy sources through improvements in energy efficiency and development of renewable energy resources, such as wind, solar, and geothermal energy.

(b) The Legislature further finds and declares that, in addition to any appropriate investments in energy production, electrical and natural gas utilities should seek to exploit all practicable and cost-effective conservation and improvements in the efficiency of energy use and distribution that offer equivalent or better system reliability, and which are not being exploited by any other entity.

(c) In calculating the cost effectiveness of energy resources, including conservation and load management options, the commission shall include a value for any costs and benefits to the environment, including air quality. The commission shall ensure that any values it develops pursuant to this section are consistent with values developed by the State Energy Resources Conservation and Development Commission pursuant to Section 25000.1 of the Public Resources Code. However, if the commission determines that a value developed pursuant to this subdivision is not consistent with a value developed by the State Energy Resources Conservation and Development Commission pursuant to subdivision (c) of Section 25000.1 of the Public Resources Code, the commission may nonetheless use this value if, in the appropriate record of its proceedings, it states its reasons for using the value it has selected.

(END OF ATTACHMENT 5)

FOOTNOTES

[1]Attachment 1 explains each technical acronym or other abbreviation that appears in this decision.

[2]The federal Public Utility Regulatory Policies Act (PURPA) of 1978 and the California Private

Energy Producers Act (see Public Utilities Code §§ 2801-2824) supply the statutory context for the development of these concepts. The decisions listed in Attachment 2 all elucidate this legislation and these concepts.

[3]These three offers are referred to as "short-run" because the energy price is computed on the basis of the purchasing utility's existing generation resources. In contrast to our final Standard Offer 4 "long-run" pricing approach, prices for these standard offers are calculated without consideration of possible resource additions. Attachment 3 summarizes the pricing provisions of our various standard offers.

[4]QFs do not avoid or defer any resource that, as analyzed in the resource planning process would *not* be cost-effective. The reason is that a prudent utility would not commit to such a resource in the first place. (See D.86-07-004, 21 CPUC 2d 340, 349 note 3 and accompanying text, 76 PUR4th 1 [1986].)

[5]The CEC adopted ER-90 on October 17, 1990.

[6]Two issues that the June 13, 1990, ruling had set for Phase 1B were later deferred. First, we have been exploring the possible extension of the BRPU cost-effectiveness methodology to test demand-side management programs. The parties agreed that presently this subject was more appropriate for workshops than for evidentiary hearings. The assigned ALJ directed workshops and "pilot" demonstrations which are continuing at this time. Second, the Commission issued Investigation (I.) 90-09-050 to consider transmission cost allocation and wholesale wheeling issues. The assigned ALJ ruled that some of the parties' proposed changes to final Standard Offer 4 were properly the subject of the transmission investigation. The Commission is presently considering initial and reply comments filed in that investigation.

[7]The record in Phase 1B consists of 35 exhibits (including hundreds of pages of prepared testimony), 12 briefs, officially noticed items (including ER-90), and about 1,500 pages of transcript. The following parties were active in the Phase 1B proceedings: Pacific Gas and Electric Company (PG&E); San Diego Gas & Electric Company (SDG&E,); Southern California Edison Company (Edison); the Commission's Division of Ratepayer Advocates (DRA); CEC; South Coast Air Quality Management District (SCAQMD); Toward Utility Rate Normalization (TURN); Coalition for Energy Efficiency and Renewable Technologies (CEERT); Geothermal Resources Association and Independent Energy Producers Association (GRA/IEP, participating jointly); Texaco Syngas Inc. (Texaco); Chevron U.S.A. Inc. (Chevron); and British Columbia Power Exchange Corporation (Powerex).

[8]In addition to analyzing non-price factors, there is ongoing work on performance features that are not currently required in our standard offer contracts but that might be provided by QFs or other electric suppliers. Such features include options, for controlling deliveries to follow the purchasing utility's load and to assist the purchasing utility in maintaining system stability. We first directed the utilities to develop such performance features in D.86-07-004 (21 CPUC 2d 340, 76 PUR4th 1 [1986]). In D.88-09-026 (29 CPUC 2d 263 [1988]), we directed the utilities to file revised reports on performance features in this Update.

[9]The record does not clearly define fuel diversity; however, our concept (adapted from testimony by PG&E witness Ross in Exhibit 207, page 6) does not appear controversial.

[10]The exceptions are Edison, which has a proposal regarding land use, and SDG&E, which could include water and land use in the post-bidding phase of the resource acquisition process that it proposes. For further discussion of parties' positions, see Section IV.D below.

[11]We will follow ER-90 usage in referring to NOx as a criteria pollutant.

[12]ER-90, page 6-12. The CEC says the predominance of NOx is due to the small amounts of SOx, PM, and ROG put out by power plants relative to their NOx emissions. Also, according to the CEC, NOx emitted from all sources is subject to stringent controls, which leads to a higher social value per ton. A third of the total residual emissions value in ER-90 came from carbon. *Id.*

[13]For the full text of Public Utilities Code § 701.1, see Attachment 5.

[14]However, these adjustments would not be reflected in the price paid to winning bidders.

[15]Note that many of these environmental costs are not captured by consideration of residual power plant emissions.

[16]We discuss this point further in Section IV.E.4.

[17]For Edison, the dominant district is SCAQMD; for PG&E, it is the Bay Area Air Quality Management District. SDG&E's service area is all or substantially all within the jurisdiction of the San Diego Air Pollution Control District (APCD).

[18]SDG&E and Edison should consult with SCAQMD in using SCAQMD values. We envision SDG&E and Edison using SCAQMD methods to derive values for the first year in their planning horizon and thereafter escalating those values using the same escalation factors employed in other elements of their resource plans.

[19]We will also revise the values for Edison, if SCAQMD actions supersede the values in today's decision.

[20]The ER-90 value for carbon emissions, and

also for NOx emissions on PG&E's system, must be converted to a first year value for purposes of ICEM. See *id.* at page 5-9.

[21]The CEC concluded that the capital intensity of non-fossil resources was unable to overtake the cost-effectiveness of gas-fired IDRs except at values for residual emissions far exceeding those used by the CEC or SCAQMD. See ER-90 at page 5-10.

[22]Edison's proposed 15% adjustment to the capital and energy costs of certain IDRs is riddled with problems. The proposal would apply only to the planning portion of resource procurement. The proposed values are highly subjective and not supported by the record. Edison needs to go back to the drawing board on this issue.

[23]Lacking a methodology for incorporating fuel diversity in our planning, we will not apply a fuel diversity premium where non-fossil IDRs appear in the deferral window, even though the use of an appropriate premium might result in the identification of more non-fossil IDRs.

[24]The two exceptions are geothermal and nuclear. However, only PG&E has much experience with geothermal. As for nuclear, its capital costs are concededly very high, and the CEC indicates that building new nuclear plants is infeasible in California at this time. (ER-90 at page 4-10.)

[25]The CEC found some evidence during ER-90 that offset prices are currently quite low. *Id.* at pages 5-7, 5-8. If that finding is correct, it seems more a reflection of the infancy of the offset market than an indication of long-term price relationships. As the cheaper offsets are bought up and offset sellers become better informed, the price of offsets should rapidly approach the buyer's marginal cost of emission control.

[26]Moreover, there may be areas with relatively good air quality (e.g., national parks) in which an increment of pollution would nevertheless be very costly. Clean air policy may not allow treating clean air as simply another commodity to be traded off until all regions have uniformly mediocre air quality.

[27]The final Standard Offer 4 QF may come on-line before the projected on-line date of the IDR (a period defined in the contract as "Period 1"); however, Period 1 payments to the QF are limited to the purchasing utility's short-run marginal costs (essentially the same as payments to a Standard Offer 1 QF). Period 2, during which payments are based on the IDR, lasts 15 years. Assuming the QF has useful life remaining at the end of Period 2, it has many options. These include continuing to operate but selling its output under Standard Offer 1 terms or bidding for another Standard Offer 4 contract from the same or a different utility.

[28]The term may be less, at the QF's election. A workshop will be held following this decision to develop appropriate revisions to the final Standard Offer 4 contract. Parties at the workshop should also consider appropriate changes to the auction protocol to ensure correct scoring of any bid by a QF proposing a contract term less than the life of the IDR.

[29]The way that the ramping method accomplishes this is summarized in D.87-05-060 (24 CPUC 2d 253, 267-68).

[30]Shortage costs are capacity payments made to short-run QFs, i.e., those QFs that do not defer or avoid new utility resources, and are also part of the capital cost payments to long-run QFs. Shortage costs measure the QF's contribution to the overall reliability of the purchasing utility's system. They are based on the annualized cost of a gas turbine, which we use as a proxy for reliability value because, in terms of capital cost, it is the cheapest current alternative for new generating capacity.

[31]The security provisions of Standard Offer 2 are probably adaptable for this purpose. We will allow the parties at workshops to consider this.

[32]"Option" is a misnomer — oil/gas-fired cogenerators *must* accept IER-based payments. However, the "option" terminology has been around so long that to replace it would only confuse matters further, so we continue to refer to the IER "option" in today's decision.

[33]The IER option combines and ramps the expected energy costs and capital costs (minus shortage costs) of the IDR, converting them into a stream of IERs. The conversion is done so that the present value of the deferred plant's fixed and operating costs is equal to the expected shortage value of the plant plus the forecast system marginal fuel price over the life of the plant multiplied by the IER stream. The expected cost of the deferred plant is equal to expected payments to cogenerators under this option. Actual payments to cogenerators are indexed to the actual system marginal fuel prices and paid on a time-differentiated basis.

[34]Hypothetically, a utility might have to turn off a baseload unit to accept QF deliveries off-peak and then be unable to restart that unit in time to meet load during the following day's peak, necessitating expensive emergency purchases from off-system sources. Since long-run QFs will now be procured strictly on the basis of need, the chance of a negative avoided cost episode occurring should become increasingly remote

[35]The formula for calculating the payment for QF energy deliveries during periods when the purchasing utility has invoked economic curtailment is contained in Section 16.3(h)(1)(ii) and Appendix J of

the uniform final Standard Offer 4 power purchase agreement. Briefly, the payment for such deliveries is the *lesser* of the utility's actual incremental cost during the curtailment hour *or* average short-run avoided operating cost based on the utility's average incremental energy rate over the total hours subject to potential economic curtailment.

[36]For example, wheat farmers may differ in their consumption of fertilizers and pesticides or in their need for irrigation. Society is also concerned with land use implications of agriculture, and farmers choosing between different crops will soon be (or already are) weighing opportunities for converting the chaff to methanol or burning the chaff in biomass facilities to generate electricity.

[37]The NRRI study is *Competitive Bidding for Electric Generating Capacity: Application and Implementation* (November 1988):

> "Second-price bidding is preferred for its strong efficiency advantages. As it is never to a bidder's advantage to submit a bid that deviates from its true cost under a second-price bidding procedure, the selection of the most efficient power producers is more likely. This cost-revelation feature also eliminates the expenses related to the analysis of the costs and bidding strategies of other potential bidders. The third advantage is that the more efficient power producers would have a stronger incentive to expand. As they expand, less efficient power producers are driven from the market resulting in a decline in the cost of electricity for the host utility and ratepayers."

Id., Executive Summary, page v. NRRI is funded by the National Association of Regulatory Utility Commissioners. The quoted material was read into the record of this proceeding by GRA/IEP witness Branchcomb (see RT 2390-91), who also endorsed the study's conclusions.

[38]PG&E, "Integrated Capacity Priority Program Proposal" (February 17, 1989), pages 40-41. Our discussion of this proposal does not indicate acceptance or rejection of the proposal or otherwise prejudge the outcome of matters pending in R.88-08-018.

[39]PG&E's pipeline capacity proposal, which is still under review, differs from our electricity auction in certain ways. The uniform price in the PG&E's proposal seems to come from the last *winner's* bid, while the uniform price here comes from the first *loser's* bid. The former method more closely follows the definition of market-clearing price, but the trade-off is that, under PG&E's proposal, there is still some incentive to bid strategically because at least one bidder will actually receive the price it bids.

Another difference is that, in PG&E's proposal, the bids are treated as confidential even after they are opened. (Only the market-clearing prices and capacities awarded would be announced, not the initial prices and capacities contained in the bids.) PG&E believes this is necessary in order for bidders to bid their true willingness to pay, without revealing possibly market-sensitive information. In our second-price auction, the bids are published after they are opened, to discourage collusion. However, confidential treatment would address PG&E witness Kahn's charge that first-price behavior would occur even in a second-price auction. We are willing to entertain proposals regarding bid confidentiality in the next phase of the BRPU.

[40]The existing safeguards would *not* work if the utility were permitted to bid against its own IDR. Such bidding would set ratepayers' interests at odds with shareholders and would subvert our concept of the IDR, which is that the IDR itself represents the utility's best judgment of how the utility, through its own means, would meet its generation needs.

If the utility could do better than the IDR, ratepayers are entitled to have that superior resource used to set the benchmark price. Utility bidding would result in an IDR "straw man" for the utility to shoot at for shareholder profit. However, the issue of utility bidding is moot given our decision, discussed in Sections III and VIII, to continue to restrict the final Standard Offer 4 auction to QFs only.

This does not mean that the utility can never "win" the competition. We suspect that some utility IDRs will withstand QF bidding. For example, QFs may not be able to match the economics of repowering. Even among non-fossil technologies, PG&E's experience with geothermal development should enable it to put together a competitive project.

[41]The term "all-source" bidding has been used to refer to almost any liberalization of the current restrictions on entities eligible to participate in the auction. There are nonutility "independent" power producers in addition to QFs, and these other power producers are the most frequently mentioned new bidders. Some parties would also allow bidding by other utilities or the purchasing utility itself. We observe, without further consideration at this time, that serious questions of self-dealing are raised by some of these proposals. For example, an "independent" power producer may be a wholly owned subsidiary of a utility. (Federal regulations limit utility equity in a QF to 50%.) When we again take up the subject of expanding the kinds of entities that may bid, we expect the proponents of such expansion also to take the initiative in proposing appropriate regulations to ensure that self-dealing does not subvert the goal of enhanced competition.

[42]Powerex indicates in its comments that it "is a wholly-owned, subsidiary of the British Columbia Hydro and Power Authority ('B.C. Hydro'), a crown corporation of the Province of British Columbia. An important mission of Powerex is to promote trade between Canadian energy developers and utilities, and United States purchasers of electric power, through mutually beneficial and environmentally sound arrangements. Powerex arranges sales of power from cogeneration and small power production facilities located in western Canada to purchasers in the United States. Powerex also arranges transmission service from these facilities to United States purchasers."

[43]Because we agree with Powerex as a matter of policy, we do not reach and express no view on, the Powerex argument regarding international trade agreement.

[44]We have previously discussed between-update power purchase opportunities. See, e.g., D.86-07-004 (21 CPUC 2d 340 at 380-81, 76 PUR4th 1 [1986]) and D.87-05-060 (24 CPUC 2d 253 at 274-75). These decisions stress that utilities may negotiate power purchase agreements at any time, but that they may not modify a long-run standard offer during the three-month solicitation period. The decisions also say that a utility considering a resource opportunity during the solicitation period must consider whether the opportunity is still attractive assuming full subscription of the solicitation at various price levels at or less than the IDR benchmark.

[45]Also, GRA/IEP propose that, when a utility executes a short-term power purchase between Updates, the capacity payment associated with the purchase should serve as the minimum capacity payment to that utility's as-available QFs, unless the Commission has explicitly approved some other floor. (Exhibit 231, page 43.) This proposal goes beyond the scope of Phase 1B but may be brought before us in Phase 3, where we will examine methodological issues, including calculation of short-run marginal costs.

[46]The reasons stated in the text compel rejecting the threshold proposals, but we also think the implications of these proposals for competition are too disturbing to ignore. The short-run avoided costs of California utilities have long been public knowledge. No buyer likes to reveal such information, but so long as there are many willing sellers, competition may be expected to result in a price lower than avoided costs. On the other hand, we see definite detriment in announcing to willing sellers how much of a discount below avoided costs is "reasonable." This kind of threshold seems unlikely to result in lower prices but could well act as a "floor." The administrative convenience that these threshold proposals provide seems small compensation for such an effect.

[47]RT 2407-08. The Commission determined the proposed purchase to be nondeferrable. See D.89-01-019 (30 CPUC 2d 574 [1989]).

[48]This procedure protects commercially sensitive information and encourages the switching QF to submit a realistic energy price. If a QF that submitted an energy price fails, within 30 days of notification by the utility of the auction result, to notify the utility of its decision whether to switch, it loses its right to switch for purposes of that auction only, and the utility returns the unopened energy price submittal.

[49]D.86-07-004 (21 CPUC 2d 340, 76 PUR4th 1 [1986]) contains rules on eligibility to bid for final Standard Offer 4 contracts. The rules say that QFs currently under contract may bid, but only after they have fulfilled their obligations under their existing power purchase agreement. However, Standard Offer 1 QFs have few such obligations. They deliver "as-available" energy and capacity, and they are contractually entitled to terminate their power purchase agreement at any time without penalty. In effect, consistent with the eligibility rules, a Standard Offer 1 QF is free to bid in any auction and need only terminate its existing contract if it wins.

[50]The as-available QF's effective capacity relates to its expected ability to deliver energy during the purchasing utility's peak hours. Effective capacity varies, based mostly on the technology that the QF uses, but effective capacity is usually a small fraction of the QF's nameplate rating.

[51]This restriction is consistent with the purpose of final Standard Offer 4, which is to defer or avoid new/additional utility generation by means of new/additional QF supply. The only existing QFs not subject to this restriction are those QFs (the "pioneers," see D.87-01-049, 23 CPUC 2d 499 [1987]) contractually entitled to switch to final Standard Offer 4.

[52]Texaco is purchasing the Cool Water Coal Gasification Plant from Edison. Texaco says it is converting that plant to a research, development, and demonstration (RD&D) project beyond the plant's original scope; it is presently applying for certification of the plant by the CEC as an RD&D project under Public Resources Code § 25540.6(e).

[53]There is no proposal to further allocate the 300 MW among the individual investor-owned utilities, nor does Texaco's testimony expressly address municipal utilities.

[54]See also our discussion of Standard Offer 2 in Section XIV below.

[55]We assume in making this assertion that the decision-maker has imperfect knowledge or control of some of the factors affecting the decision. If resource planners had perfect knowledge of all possible outcomes and the likelihood of each outcome, we would not need to consider uncertainty. In reality, experts hold widely divergent views on all major resource planning variables, and even the existence of a broad consensus is no guarantee that the consensus view will prove accurate.

[56]In our first resource plan review for final Standard Offer 4, we considered a "go short" strategy proposed by SDG&E. That strategy called for reserving a portion of long-term need (as defined by SDG&E) to be met by power purchase opportunities outside the auction. SDG&E supported this strategy on the grounds that capacity surpluses existed outside its service area, and that premature commitment to QFs had an opportunity cost in the form of displacing potentially more cost-effective purchases from other sources.

We did not specifically reject or endorse this "go short" strategy, because we found that SDG&E then had only nondeferrable resource additions in its resource plan. However, we noted that "the capacity made available for possible deferral, by QFs . . . might be *less* than that suggested by use of the CEC's projections of supply and demand." We might choose that strategy "if, after uncertainty analysis considering the risks and benefits, it appears to optimize results for ratepayers." D.86-11-071 (22 CPUC 2d 311, 320 [1986]).

[57]The Standard Offer 2 QF also has the option of having its capacity price projected at the time it comes on-line, but most QFs choose to take the capacity schedule in effect at the time their contract is signed.

[58]See D.86-03-069 (mimeo.); D.86-05-024 (21 CPUC 2d 124 [1986]).

[59]See D.88-03-079 (27 CPUC 2d 559, 566-68, 91 PUR4th 143 [1988]).

[60]Moreover, the payment structure of Standard Offer 2 mirrors that of a gas turbine; this would limit the usefulness of the offer in acquiring capital-intensive QFs. See the analysis of payment structure in Section V above.

[61]SDG&E is presently revising its pilot program for applying ICEM to DSM cost-effectiveness analysis. PG&E and Edison are presently conducting their own pilots to investigate this type of integrated planning. Each utility should include its findings in its compliance report for the ER-90 phase.

[62]An exception can be made if progress in the transmission investigation has reached the point where we should consider making conforming changes to final Standard Offer 4.

[63]We received comments from PG&E, SDG&E, Edison, CEC, DRA, SCAQMD, GRA/IEP, CEERT, TURN, Texaco, and Powerex. We also received reply comments from PG&E, Edison, DRA, SCAQMD, TURN, GRA/IEP, CEERT, Texaco, and Chevron.

[64]We have also made other changes to improve the discussion, add references to the record, or correct typographical errors.

[65]This is the process we followed successfully in our implementation of the 1986 Update decision, where the parties were able to agree on most contract drafting issues, but where we also heard and decided proposed alternative provisions supported by some of the parties. See D.88-03-079 (27 CPUC 2d 559, 576-82, 91 PUR4th 143 [1988]).

Attachment 3

[1]Source: D.88-09-026 (29 CPUC 2d 263 [1988]) (in A.82-04-44 et al.), Appendix D.

Attachment 4

[1]Source: D.88-09-026 (29 CPUC 2d 263 [1988]) (in A.82-04-44 et al.), Appendix A.

Re Eastern Edison Company

D.P.U. 90-141

Massachusetts Department of Utilities
June 14, 1991

ORDER issuing generic findings on how to measure environmental externality costs of various resource bids, as part of review of an electric utility's request for proposals from qualifying facilities for long-term power sales. For prior order adopting integrated resource management rules, see *Re Integrated Resource Management Practices*, 116 PUR4th 67 (Mass.D.P.U.1990).

1. ELECTRICITY, § 4 — Generating plants — Capacity solicitation — Bidding procedures.

[MASS.] An electric utility's third request for proposals from qualifying facilities to provide electrical energy and capacity under long-